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S.C. Supreme Court

APPEAL FROM THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA
Appellate Case No. 2013-000529

South Carolina Energy Users Committee,

Appellant-Respondent,

v.

**South Carolina Electric & Gas, Office of Regulatory
Staff, Pamela Greenlaw,**

Respondents,

and Sierra Club, is Respondent-Appellant.

RECORD ON APPEAL – VOLUME II

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1 A I have.

2 Q Would you please deliver that at this time?

3 A Yes. Good morning, Mr. Chairman and members of the
4 Commission.

5 My testimony presents the current staffing plans
6 for the operational readiness, nuclear security and
7 construction oversight, and quality assurance/quality
8 control -- or our QA/QC -- functions of the New Nuclear
9 Deployment group, or NND. Specifically, I discuss the
10 process by which current staffing plans were created and
11 their impact on owners' costs.

12 During the 2008-to-2010 timeframe, SCE&G reviewed
13 the initial staffing, hiring, and training plans for the
14 project. The initial versions of these plans had been
15 compiled prior to the signing of the EPC contract. They
16 were largely based on benchmark information that was
17 gathered from the Electric Utility Cost Group, the
18 Nuclear Energy Institute, the Electric Power Research
19 Institute, Westinghouse, and the Institute of Nuclear
20 Power Operations. The Operational Readiness group
21 reviewed these plans to ensure that a full complement of
22 trained personnel would be in place to operate the units
23 prior to fuel load. These personnel must also accept
24 the security, testing, and maintenance responsibilities
25 for the major systems as turnovers occur throughout the

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1 construction process. Staffing plans that resulted from
2 this review were presented to the Commission in the 2010
3 docket and were approved in 2011.

4 Since 2011, we have continued to review the
5 staffing plans as new information has emerged concerning
6 the design of the plant, regulatory requirements coming
7 from the Fukushima event, physical security requirements
8 for the plant, challenges concerning retaining and
9 certifying operating personnel, and similar matters.
10 During the latter part of 2011, a group of experienced
11 personnel with diverse backgrounds in nuclear
12 operations, safety, security, plant operations and
13 maintenance, engineering, quality systems, training,
14 construction, planning and scheduling, outage,
15 organization development, licensing, health physics,
16 chemistry, documents and records, materials and
17 procurement, and emergency planning were assembled as
18 challenge boards. The challenge boards recommended
19 adjustments to the staffing levels.

20 The challenge boards concluded that an additional
21 124 full-time equivalents, or FTEs, in Operational
22 Readiness in construction oversight and QA/QC, and an
23 additional 20 FTEs for the nuclear security contracts
24 were needed to operate the units in a safe and cost-
25 effective manner. The total staffing-related

1 adjustments being presented here is \$72.3 million, which
2 represents the addition of 144 full-time equivalents to
3 the staffing plan.

4 On a functional basis, these areas consist of
5 emergency planning/health physics; operator and training
6 margin; programs and procedure development; timing
7 variance, which supports craft and technical training;
8 nuclear construction oversight; QA/QC; security
9 contractors; and a category referred to as "other."

10 The change within the emergency response/health
11 physics category is the result of emerging regulatory
12 limits on collateral responsibilities that can be
13 assigned to emergency response personnel. In response
14 to the events at Fukushima, the Nuclear Regulatory
15 Commission determined that emergency responders should
16 not have certain collateral duties. Reevaluating these
17 duties resulted in the addition of four full-time
18 equivalents to the staffing plan.

19 The Operational Readiness team must ensure that,
20 before initial fuel load, SCE&G has hired, trained, and
21 licensed a sufficient number of nuclear reactor
22 operators to operate each of the units safely and
23 reliably on a 24-hour-a-day basis. Given the nature of
24 today's military, fewer candidates with reactor operator
25 qualifications and experience are available for hire.

1 In addition, industry experience has demonstrated a
2 higher degree of difficulty in passing the Nuclear
3 Regulatory Commission licensing exam program for new
4 licensees. The fact was recently highlighted when
5 another utility experienced a higher-than-expected
6 failure rate for the pool of candidates on the initial
7 licensed operator exam.

8 To account for this, we have increased the number
9 of people that we recruit and hire, to allow for
10 additional training time and to account for attrition.
11 This change in the staffing plan resulted in 30
12 additional full-time equivalents being added to the
13 staffing plans for the units.

14 In anticipation of constructing the units, SCE&G
15 and four other utilities formed a group known as the
16 APOG. Each of these APOG utilities had submitted an
17 application to the Nuclear Regulatory Commission for a
18 license for AP1000 units. The agreement had been to
19 share the costs of developing and documenting plant
20 programs and procedures necessary to operate and
21 maintain the units. However, due to confidentiality
22 concerns, only utilities that have executed EPC
23 contracts can now share the information necessary to
24 develop these procedures. This occurred in the mid-2011
25 timeframe. SCE&G and Southern, the only two utilities

1 with active EPC contracts, must now develop these
2 programs and procedures alone.

3 To manage the expanded role of the company in these
4 efforts and the company reduction in informational
5 resources available through the APOG group, SCE&G is
6 accelerating the hiring of engineers to develop these
7 programs and procedures. It's also expanded the size of
8 the engineering staff to ensure continued program
9 support and maintenance of these programs into plant
10 operations. The result of these actions is an increase
11 in owners' costs of 22 full-time equivalents.

12 The standards for required training and testing of
13 craft and technical employees that will maintain the
14 units have also become more stringent in recent years.
15 These employees must be trained in accordance with the
16 INPO -- Institute of Nuclear Power Operations --
17 accredited training programs, which are designed to meet
18 or exceed nuclear regulatory requirements. SCE&G has
19 decided that it is important to accelerate this training
20 to provide trainees with as much hands-on experience as
21 possible before the units go into operation.

22 The areas where training and hiring schedules are
23 accelerated are chemistry, maintenance, outage, and
24 planning and scheduling. The early hiring of craft and
25 technical employees and the addition of three full-time

1 equivalents has resulted in an increase to the staffing
2 plan.

3 SCE&G's experience thus far has led it to the
4 conclusion that additional oversight personnel are
5 necessary to effectively oversee the project. We must
6 ensure compliance with QA/QC requirements, nuclear
7 regulatory requirements, and our engineering,
8 procurement, and construct contract.

9 Originally, SCE&G understood that its oversight
10 role would be primarily in reviewing and auditing the
11 Westinghouse and Shaw QA/QC programs. However, our
12 experience has shown us that there's no substitute for
13 the focused oversight of the project by its owner. The
14 NRC has made it very clear that it holds SCE&G
15 ultimately accountable, as the owner and licensee, for
16 the operating units, and for the quality, reliability,
17 and safety of the units as constructed. The NRC has
18 encouraged us to be actively and directly involved with
19 overseeing all aspects of the work, and we agree.

20 SCE&G has added 26 full-time equivalent hires to
21 provide for expanded resources in the quality assurance/
22 quality control areas.

23 The "other" categories shown in Exhibit B to my
24 testimony consists of personnel needed to facilitate
25 such things as the transfer of construction and

1 engineering documentation from Westinghouse/Shaw to
2 SCE&G, and to provide adequate security of documents
3 classified safeguarded material during the construction
4 phase. The "other" category also reflects decreases in
5 full-time equivalents in areas like business and
6 finance. The analysis resulted in a net increase of
7 three full-time equivalents in this area.

8 The final category is security contracting. As
9 holder of the NRC license, SCE&G must ensure the
10 physical security of the site. Consistent with industry
11 practice, SCE&G maintains a core group of internal
12 security personnel, but principally relies on
13 contractors for this function. The layout and
14 configuration of the units and the supporting buildings,
15 access points, and site topography inform the decisions
16 regarding security contractor staff size. For the
17 finalization of the site layout, SCE&G has revised the
18 staffing plans for security to add 20 additional FTEs in
19 this area.

20 This represents the principal drivers of the change
21 in personnel accounts reflected in these updates. Based
22 on my 38 years of experience in the nuclear industry and
23 my involvement in these reviews, I consider them to be
24 reasonable and necessary costs for the project, and not
25 the result of imprudence by SCE&G.

1 **MR. GISSENDANNER:** Thank you, Mr. Lavigne.
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23 **[PURSUANT TO PREVIOUS INSTRUCTION, THE**
24 **PREFILED DIRECT TESTIMONY OF DAVID A.**
25 **LAVIGNE FOLLOWS AT PGS 555-572]**

DIRECT TESTIMONY OF

DAVID A. LAVIGNE

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2012-203-E

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is David Lavigne. My business address is 1162 State Highway 213, Jenkinsville, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as General Manager, Operational Readiness for New Nuclear Deployment ("NND"), for South Carolina Electric & Gas Company ("SCE&G" or the "Company").

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I have a Bachelor of Science Degree in Management from the University of South Carolina and possess a Senior Reactor Operator Certification. I joined SCE&G in January 1977 as a quality specialist for V.C. Summer Unit 1 after serving six years in the Navy Nuclear Power Program, including an assignment as a nuclear submarine operator. While at the Company, I have held positions of Quality Assurance Specialist; Associate Manager, Quality Assurance; Manager Nuclear Quality Control; Manager, Materials and Procurement; General Manager,

1 Nuclear Safety; and General Manager, Nuclear Support Services. In 2002, I was
2 named General Manager, Organizational Effectiveness and served in that role for
3 9 years. My duties during that time included Organizational Development and
4 Performance ("OD&P"), Quality Systems, Security, and Document Control. In
5 2010, I was transferred to my current position as General Manager, Operational
6 Readiness in connection with the construction and operation of two Westinghouse
7 AP1000 nuclear generating units in Jenkinsville, South Carolina (the "Units").

8 **Q. PLEASE DESCRIBE EXHIBIT NO. __ (DAL-1).**

9 A. Exhibit No. __ (DAL-1) describes the structure of the NND Teams that I
10 will be discussing.

11 **Q. WHAT ARE YOUR DUTIES WITH SCE&G?**

12 A. As General Manager of Operational Readiness for New Nuclear
13 Deployment, I am responsible for all staffing and support functions associated
14 with SCE&G's readiness to operate Units 2 and 3 safely, reliably and efficiently
15 once completed. The staff that we are assembling to carry out the permanent
16 operations of the Units will also take primary responsibility for the maintenance
17 and startup testing of the Units as systems are completed and turned over to
18 SCE&G.

19 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION IN THE**
20 **PAST?**

21 A. Yes. I have testified before the Public Service Commission of South
22 Carolina (the "Commission") in a past fuel clause proceeding.

1

2 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

3 A. The purpose of my testimony is to present the current staffing plans for the
4 Operational Readiness, Nuclear Security and Construction Oversight and Quality
5 Assurance/Quality Control ("QA/QC") functions of NND associated with the
6 construction and eventual operation of Units 2 and 3. Specifically, I discuss the
7 process by which the current staffing plans were created and their impact on
8 Owners cost. Chart A shows in detail the current staffing plan of the project as
9 compared to the plan that appeared in Docket No. 2010-376-E.

10 **Q. COULD YOU DESCRIBE WHERE YOU STARTED IN REVIEWING THE**
11 **STAFFING PLANS?**

12 A. As the Commission is aware from prior proceedings, in the period 2008-
13 2010, SCE&G intensively reviewed the initial staffing, hiring and training plans
14 for the project. The initial versions of these plans had been compiled prior to the
15 signing of the EPC Contract, based on the information available at the time,
16 including benchmark information that was gathered from the Electric Utility Cost
17 Group ("EUCG"), the Nuclear Energy Institute ("NEI"), the Electric Power
18 Research Institute ("EPRI"), Westinghouse and the Institute of Nuclear Power
19 Operations ("INPO").

20 In our initial review of these plans, the Operational Readiness group sought
21 to ensure that a full complement of thoroughly-trained personnel would be in place
22 to operate the Units prior to fuel load and to accept the security, testing and

1 maintenance responsibility for major systems as turnovers occur throughout the
2 construction process. We also sought to ensure that the plan included the
3 personnel necessary to oversee construction, engineering, QA/QC, licensing and
4 project financial and commercial issues during the construction project.

5 **Q. WHAT ACTION DID YOU TAKE WITH THESE PLANS?**

6 A. The staffing plans that resulted from this review were presented to the
7 Commission in Docket No. 2010-376-E and were approved.

8 **Q. PLEASE DESCRIBE THE PROCESS BY WHICH YOU HAVE UPDATED**
9 **THE PLANS PRESENTED IN DOCKET NO. 2010-376-E.**

10 A. Since 2011, we have continued to review our staffing plans as new
11 information has emerged concerning the design of the plant, regulatory
12 requirements such as those forthcoming from the Fukushima event, physical
13 security requirements for the plant, challenges concerning retaining and licensing
14 operating personnel, and similar matters. During this period, we conducted
15 extensive interviews with the leadership of each department of the current
16 operating unit, Unit 1, and with each department involved in the construction and
17 operational readiness of the new Units. During the latter part of 2011, a group of
18 experienced personnel with diverse backgrounds in nuclear operations, safety,
19 security, plant operations and maintenance, engineering, quality systems, training,
20 construction, planning and scheduling, outage, OD&P, licensing, chemistry,
21 documents and records, materials and procurement, health physics, and emergency
22 planning was assembled as "challenge" boards. The role of the challenge boards

1 was to review and validate the assumptions for the staffing levels presented by
2 each area of NND Operational Readiness. The challenge boards recommended
3 adjustments up and down in staffing levels. But on the whole, their conclusion
4 was that the plan presented did not provide for the hiring and training of sufficient
5 personnel for SCE&G to conclude that projected staffing and training levels would
6 be sufficient to startup and operate the Units reliably and effectively.

7 **Q. WHAT DID YOU DO WITH THIS INFORMATION?**

8 A. As a result of the input from these challenge boards, adjustments to staffing
9 levels were made and presented to SCE&G's nuclear leadership team for review.
10 Concurrently, the Construction Oversight and QA/QC group within NND
11 conducted an internal review of staffing requirements for the Construction
12 Oversight and QA/QC functions in support of the construction project. They
13 conducted this review in light of the four years of experience they had gained with
14 the level of staffing that was actually required for SCE&G to fulfill its role as
15 owner in this project, and the high level of oversight and accountability that the
16 NRC expected of SCE&G in this role. At the completion of their work, they
17 presented their conclusions to SCE&G's nuclear leadership team for review.

18 **Q. WHAT WAS THE RESULT OF THESE REVIEWS AND ADJUSTMENTS?**

19 A. This analysis and review has resulted in the addition of 95 Full Time
20 Equivalents ("FTEs") in Operational Readiness, and 20 additional FTEs for the

1 nuclear security contractors. The associated cost is \$60.6 million.¹ The analysis
2 and review of the Construction Oversight, QA/QC, and other project support
3 functions has resulted in the addition of 29 FTEs to the staffing plan, or \$11.7
4 million to Owners cost.

5 The total staffing-related adjustment being presented here is \$72.3 million,
6 which represents the addition of 144 FTEs to the staffing plan. These figures are
7 presented in Chart A below.

¹ Unless otherwise specified, all cost figures in this testimony are stated in 2007 dollars net of Allowance for Funds Used During Construction and reflect SCE&G's share of the cost of the Units.

1

Chart A

Full Time Equivalents (FTE)			
New Nuclear & Operational Readiness Labor Variance			
	Order 2011 345 PSC Approved Budget	Proposed Staffing Plan	Delta
Group	Full Time Equivalents Units 2 & 3	Full Time Equivalents Units 2 & 3	Increase to Owner's Plan
Management Admin	2	2	0
Operations	141	167	26
Maintenance	144	128	-16
Planning & Scheduling	26	36	10
Outage	3	7	4
Business & Financial	29	22	-7
Engineering	85	107	22
Licensing	15	16	1
Emergency Services	4	27	23
Health Physics	44	61	17
Chemistry	26	31	5
Training	54	58	4
Security (SCE&G only)	22	25	3
Quality Systems	7	27	20
OD&P	11	16	5
Recs, Docs, & Repro	4	10	6
Construction	19	20	1
Total	636	760	124
Security Contractors			20
Total			144

2

3

4

1 Q. COULD YOU PLEASE PROVIDE A BREAKDOWN OF THE FUNCTIONS
2 THAT IMPACTED THE STAFFING ANALYSIS?

3 A. The staffing categories contained in Chart A reflect departments and not
4 functions. There are several functional areas that cut across these staffing
5 categories. On a functional basis, these areas consist of Emergency
6 Planning/Health Physics, Operator/Training Margin, APOG/Programs/Procedures,
7 Timing Variance to Support Craft and Technical Training Program, Nuclear
8 Construction Oversight and QA/QC, Other, and Security Contractors.

9
10 CHART B

<u>Changes by Functional Cause</u>		
Cause	FTE Change	Cost Change (millions)
Emergency Planning/Health Physics (Fukushima)	40	\$5.9
Operator/Training Margin	30	\$17.4
APOG / Programs / Procedures	22	\$15.7
Timing Variance to Support Craft and Technical Training Program	3	\$15.5
Nuclear Construction Oversight and QA/QC	26	\$8.6
Other	3	\$3.1
Total SCE&G	124	\$66.2
Security Contractors	20	\$6.1
TOTAL	144	\$72.3

11

1 Q. COULD YOU PLEASE EXPLAIN THE IMPACT OF THE EMERGENCY
2 PLANNING/HEALTH PHYSICS CATEGORY ON THE STAFFING
3 ANALYSIS?

4 A. Much of the change in this emergency response/health physics category is
5 the result of emerging regulatory limits on the responsibilities that can be assigned
6 to emergency response personnel. In the past, emergency response personnel at
7 operating nuclear units have been assigned additional duties with the
8 understanding that these additional duties would not interfere with their core
9 duties in case of an emergency. In response to the events at Fukushima, the NRC
10 determined that many of these additional duties may interfere with emergency
11 response functions in a prolonged and wide-spread emergency event. As a result,
12 the NRC began rulemaking proceedings to limit the number of collateral duties
13 that may be assigned to emergency personnel during a multi-unit response. These
14 formal rulemaking proceedings are not yet complete and will continue to require
15 further analysis. The NRC published guidance in this area in November 2011 and
16 the Nuclear Energy Institute has drafted an implementing document setting forth
17 how the nuclear industry will meet the announced requirements of the NRC
18 rulemaking.

19 It is the practice in our industry to meet emerging safety and reliability
20 issues proactively rather than waiting for regulatory mandates. So based on the
21 information emerging in this area, SCE&G has evaluated the impact on the
22 staffing plan for the Units of limiting emergency personnel's collateral duties.

1 Limiting those duties results in an additional 40 FTEs being added to the staffing
2 plan. The cost associated with some of these FTEs will be shared with Unit 1, and
3 the Unit 1 share of their cost is not reflected in this filing. The result is an increase
4 of \$5.9 million in forecast of Owners cost for the new Units. This is the amount
5 identified to date, based on the initial guidance given in the tier 1 Fukushima
6 regulations. This rulemaking process could result in additional requirements.

7 **Q. PLEASE DESCRIBE THE IMPACT OF OPERATOR AND TRAINING**
8 **MARGINS ON THE STAFFING ANALYSIS.**

9 A. A key responsibility of the Operational Readiness team is to ensure that
10 before initial fuel load SCE&G has hired, trained and licensed a sufficient number
11 of nuclear reactor operators to operate each of the Units safely and reliably 24
12 hours a day seven days a week. Our staffing plan must ensure that there are
13 enough operators available to account for the time required for vacations, in-
14 service training, recertification and re-licensure, sick leave, family leave and other
15 times when individual operators will be unavailable for duty in the control room.
16 The training process for licensing nuclear reactor operators is demanding and
17 takes approximately 3-7 years to complete based on previous incumbent
18 experience.

19 One of the challenges in preparing a staffing plan for a start-up unit is
20 anticipating how many candidates must be hired at the start of the process to
21 ensure an adequate number of licensed operators are on hand when the Units go
22 into service. Over the past year, SCE&G has revised its staffing plans for nuclear

1 reactor operators to take into account the likelihood that attrition during training
2 will be higher than initially forecasted and that more candidates than originally
3 anticipated will fail to complete the training and licensing program successfully.

4 **Q. WHY DO YOU BELIEVE THAT ATTRITION AND FAILURE RATES**
5 **MAY BE HIGHER THAN ANTICIPATED?**

6 A. This conclusion is based in part on SCE&G's experience over the past four
7 years in recruiting qualified applicants for its reactor operator positions at Unit 1
8 and at the new Units. The nuclear power industry has entered a period in which a
9 large number of qualified operators are reaching retirement age. Given the nature
10 of today's military, fewer candidates with reactor operator qualifications and
11 experience are available for hire. As a result, SCE&G has found that the
12 competition for qualified candidates is greater than it has been in the past, and we
13 see candidates with less direct experience in reactor operations than in the past. As
14 a result, the likelihood of trainees being hired away by other utilities, or simply
15 deciding that this career is not for them, is greater than in the past. In addition,
16 industry experience has demonstrated a higher degree of difficulty in passing the
17 NRC licensing program for new licensees. This fact was highlighted recently
18 when another utility experienced a higher than expected failure rate for a pool of
19 candidates on the initial licensed operator exam. In sum, we must train less
20 experienced candidates with less practical exposure to the work to meet higher
21 licensing standards while facing greater competition to retain them.

1 **Q. HOW HAS SCE&G RESPONDED TO THESE CONCERNS?**

2 A. To ensure that there is a sufficient pool of operators to operate the Units
3 prior to initial fuel load, SCE&G has increased its estimates of the attrition and
4 failure rates among its reactor operator candidates. SCE&G has increased the
5 number of candidates that it will hire and train to support plant start-up.

6 **Q. WHAT IS THE RESULT OF THIS CHANGE IN THE STAFFING PLAN?**

7 A. This change in the staffing plan results in 30 additional FTEs being added
8 to the staffing plans for the Units representing \$17.4 million of the adjustment in
9 forecasted costs.

10 **Q. HOW DO CHANGES IN THE DEVELOPMENT OF PROGRAMS AND**
11 **PROCEDURES AND THE EFFECTIVENESS OF APOG AFFECT**
12 **OWNERS COST?**

13 A. As the Commission is aware, the Company is a member of APOG, a group
14 of five utilities who have each submitted applications to the NRC to license
15 AP1000 units. Among its other functions, APOG supports the efforts of the
16 owners of AP1000 units to develop and document approximately 100 plant
17 programs (such as the Thermal Performance Program, the Equipment Reliability
18 Program, and the System Status Control Program) and approximately 4,200
19 individual procedures that will be required to operate and maintain the Units.
20 Those programs and procedures must be in place before initial fuel load for the
21 new Units can take place.

22

1 **Q. HOW HAS APOG'S ROLE IN THE PROJECT CHANGED?**

2 A. Prior staffing plans for the Units were based on the understanding that
3 SCE&G would be one of five APOG utilities sharing the burden of drafting the
4 required programs and procedures. However, personnel working on these tasks
5 must have on-going access to detailed information concerning the design and
6 technology contained in the Units and their operating parameters. This is
7 information which the EPC Contract protects as confidential. Only two of the five
8 AP1000 license applicants, SCE&G and the Southern Company, currently have
9 active EPC contracts with Westinghouse/Shaw and so have access to this
10 information. In 2011, Westinghouse/Shaw determined that those utilities which
11 do not have active EPC contracts cannot have access to the proprietary
12 information that is required to participate in this work. As a result, only SCE&G
13 and Southern Company can currently collaborate in developing this large body of
14 programs and procedures.

15 **Q. HOW HAS THIS AFFECTED YOUR STAFFING PLANS?**

16 A. This decision initiated a comprehensive assessment of the overall approach
17 used to support engineering programs prior to and after initial fuel load. To
18 manage the expanded role of the Company in these efforts, and the accompanying
19 reduction in information and resources available to the Company through APOG,
20 SCE&G is accelerating the hiring of engineers to develop these programs and
21 procedures. Additionally, the overall engineering staff size was increased to assure
22 continued program support and maintenance into the operational phase of the

1 Units. The result of these actions is an increase to Owners cost of 22 FTEs at a
2 cost of \$15.7 million.

3 **Q. PLEASE EXPLAIN HOW SCE&G'S PLANS RELATED TO CRAFT AND**
4 **TECHNICAL TRAINING PROGRAMS HAVE CHANGED.**

5 A. As indicated above, SCE&G has increased its hiring of reactor operator
6 candidates in part because the standards for the required training and testing have
7 become more stringent in recent years. The craft and technical employees that will
8 operate the Units must also be trained in accordance with the INPO accredited
9 training programs, which are designed to meet or exceed all NRC requirements.
10 SCE&G has revised the time and costs associated with its training plans for
11 candidates for craft and technical positions. These positions are in the areas of
12 chemistry, maintenance, outage and planning, and scheduling. This required
13 training also requires us to hire these positions earlier. We have further
14 accelerated the training and hiring schedules so that candidates can complete their
15 training and qualification earlier, so that they will have more time to get hands-on
16 practical experience with nuclear operations before initial fuel load for the Units.

17 **Q. PLEASE EXPLAIN WHY THIS IS IMPORTANT.**

18 A. While training itself is critically important, we also believe that it is
19 important that the craft and technical staffs for the Units get as much hands-on
20 experience as possible before the Units go into operation. By accelerating the
21 training schedule, we make it possible for these craft and technical employees to
22 have the opportunity to work with the start-up and testing teams for the Units and

1 to work alongside their colleagues on Unit 1 who have similar responsibilities.
2 This will allow new hires to gain greater hands-on experience in their new
3 functions before commercial operations begin.

4 **Q. WHAT IS THE IMPACT ON STAFFING AND COST FORECASTS?**

5 A. The early hiring of craft and technical employees and the addition of 3
6 FTEs have resulted in anticipated cost increases to Owners cost of approximately
7 \$15.5 million.

8 **Q. PLEASE EXPLAIN THE STAFFING CHANGES REQUIRED IN THE**
9 **CATEGORY OF NUCLEAR CONSTRUCTION OVERSIGHT AND**
10 **QA/QC.**

11 A. Experience overseeing the construction of the Units to date has led the
12 Company to conclude that additional oversight personnel are necessary to
13 effectively oversee the project and ensure compliance with NRC QA/QC
14 requirements, adherence to the terms of the EPC Contract, and the ultimate
15 success of the construction program. This was discussed in detail in the testimony
16 of Mr. Byrne. When the original staffing estimates were made, we assumed that
17 SCE&G's role would be less "front line" and more focused on oversight of
18 Westinghouse/Shaw's QA/QC programs as inspected and audited by the NRC.
19 Experience has shown us that while our contractors' QA/QC programs are
20 meeting regulatory requirements, there is no substitute for the accountability
21 provided by an owner's direct involvement and insistence on quality and timely
22 work. The NRC concurs in this, and has made it very clear that they hold SCE&G

1 ultimately accountable as owner/licensee for the quality, reliability and safety of
2 the Units as constructed. They expect SCE&G to be actively and directly involved
3 in overseeing all aspects of the work and we agree. The value of additional
4 personnel to oversee the construction effort and the world-wide procurement chain
5 for this project cannot be overstated. For this reason, SCE&G has added 26 FTE
6 hires totaling approximately \$8.6 million to provide for this critical role.

7 **Q. PLEASE EXPLAIN THE "OTHER" CATEGORY AND HOW CHANGES**
8 **TO THOSE ITEMS IMPACT STAFFING AND OWNERS COST.**

9 A. The transfer of documentation from Westinghouse/Shaw to SCE&G is a
10 process that needs to start earlier than previously anticipated to assure all relevant
11 information is captured in the SCE&G records system for current and future use.
12 Additionally, lessons learned from fitness for duty and access control violations at
13 other utility's facilities warranted increased focus on these areas as well. Security
14 personnel were also added to assure positive control of nuclear safeguards
15 information during the construction phase of the project. Finally, other staffing
16 evaluations resulted in staff decreases in areas like business and finance. The
17 analysis shows an increase of 3 FTEs in this category totaling approximately \$3.1
18 million.

19 **Q. PLEASE EXPLAIN THE SECURITY CONTRACTOR CATEGORY AND**
20 **HOW CHANGES TO IT IMPACT STAFFING AND OWNERS COST.**

21 A. One of the key responsibilities SCE&G has as holder of the NRC licenses
22 for the Units is to ensure the physical security of the site. As is typical in the

1 industry, SCE&G maintains a core group of internal security personnel, but
2 principally relies on contractors for this function.

3 The security staff for a nuclear unit is based on threat response planning
4 that takes into account the layout and configuration of the Units and their
5 supporting buildings, access points and site topography. These plans are very
6 specific and detailed documents can only be completed as the site layout is
7 finalized including all ancillary buildings. In addition, these threat response plans
8 must conform to current guidance from the NRC and the industry and the nature
9 and severity of the threats that can be anticipated.

10 Based on changes to the site layout as a result of finalizing engineering
11 plans for things like employee access points and the location of ancillary
12 buildings, and based on current guidance as to threats to be taken into account,
13 SCE&G has revised its staffing plans for security to add 20 additional FTEs in this
14 area at a cost of approximately \$6.1 million.

15 **Q. HOW DID YOU ASCERTAIN THE REASONABLENESS OF THE**
16 **ADDITIONAL COSTS PROPOSED HERE?**

17 **A.** I have personally reviewed the budget forecasts presented here to ensure
18 that the costs they include are reasonable and necessary. We are very sensitive to
19 the need to control costs on this project. SCE&G management has been
20 unrelenting in its review of the reasonableness of this plan and its insistence that
21 the entire project team remain fully committed both to controlling costs and to
22 ensuring the success of the project. Each team within NND and NND leadership

1 has been required to justify the necessity of each position and the timing of each
2 hiring date. Based on my 38 years of experience in the nuclear industry, and my
3 involvement in these reviews, it is my opinion that these costs are reasonable and
4 prudent and reflect a strong commitment to control costs where possible without
5 unreasonably putting the success of the project at risk.

6 **CONCLUSION**

7 **Q. WHAT ARE YOU REQUESTING THIS COMMISSION TO DO?**

8 A. The Company is requesting that the Commission approve, pursuant to S.C.
9 Code Ann. § 58-33-270(E), the updated capital costs schedule in Exhibit No. ____
10 (CLW-1) as the approved schedule of capital costs for the Units.

11 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

12 A. Yes, it does.
13

1 plans for the project, correct?

2 A Yes, sir, I did.

3 Q All right. Now, would it be fair to say, Mr. Lavigne,
4 that, looking at the early phase -- the early part of
5 that 2008-2010 timeframe -- that in the early phase,
6 around the time of initial submittal to the PSC in 2008
7 of the Base Load application, staffing input was
8 gathered from Westinghouse, the other APOG utilities,
9 and SCE&G? Is that a fair statement?

10 A Yes.

11 Q And is it also fair to say that the data that you
12 collected -- that the company collected -- was based on
13 general estimates and preliminary design information?
14 Is that fair to say?

15 A Well, general estimates -- there were a lot of industry
16 involvement and a lot of benchmarking activity that had
17 been performed, so all of that was brought together and
18 an informed decision made relative to what the projected
19 staffing would be for the advanced passive design.

20 Q All right, sir. And that's in 2008, correct?

21 A That's correct.

22 Q But, understanding that you got a great deal of
23 information from Westinghouse, the other APOG utilities,
24 and in-house at SCE&G, it is still accurate to say that
25 the data that you put together and presented to this

1 Commission in 2008 was based on general estimates and
2 preliminary design information, correct?

3 A As I stated earlier, I think it was more than just
4 general estimates of preliminary design. It was also
5 inclusive of a number of benchmarking information that
6 was accumulated through industry evaluations and
7 industry contacts, to determine what those reasonable
8 and appropriate staffing levels would be for where we
9 were at that point in the plant development.

10 Q All right. So if I understand your answer, it was based
11 on more than general estimates and preliminary design
12 information. SCE&G had a great deal of information
13 available to it in 2008 when it applied for its Base
14 Load order. Is that your testimony?

15 A I would say we had a lot of information. When you
16 characterize things with adjectives, it makes it
17 difficult.

18 Q All right, sir. Well, I tell you, the difficulty I'm
19 having is that, as you may be aware, in the give-and-
20 take process that leads up to this hearing, the parties
21 -- in my case, the South Carolina Energy Users'
22 Committee -- will ask a question of SCE&G, your
23 employer, about issues important to it in the docket.
24 You understand that, don't you, sir?

25 A Yes.

1 Q And --

2 A And the public.

3 Q And you understand that, in this case, the South
4 Carolina Energy Users' Committee sent what we call data
5 requests to your employer, SCE&G, and in particular,
6 asked questions about the staffing plans. Do you recall
7 that?

8 A Yes.

9 Q All right. And so, in response to a data request, 1-4,
10 we were provided a staffing analysis. Do you recognize
11 that [indicating]?

12 A Yes, I do.

13 Q All right. And I have asked you a couple of questions
14 about this, regarding the language I have highlighted.
15 And one thing we were told was -- and, in particular, my
16 question -- the data was based on general estimates and
17 preliminary design information. Do you see that
18 language there?

19 A I wrote that language.

20 Q All right.

21 A I'm very familiar with it.

22 Q Very fine. I thought you would be, or I wouldn't have
23 imposed on you.

24 A Thank you.

25 Q Now --

1 A Well, let me clarify.

2 Q By all means, yes.

3 A As I indicate in my direct testimony -- we talked about
4 general estimates; that was, again, my language and I
5 was writing a response to an information request.
6 What's in the direct testimony refers to the fact that
7 that information -- and I indicated "Benchmark, other
8 organizations" -- those were the reviews that were done
9 that included the Nuclear Regula- -- excuse me -- the
10 Electric Utility Cost Group, Nuclear Energy Institute,
11 Institute of Nuclear Power Operations, and Westinghouse,
12 as well as other utility groups. So there was a very
13 comprehensive look at what the staffing levels would be
14 and would be necessary to support the plant.

15 Q All right. So you did all this in advance of your 2008
16 application, correct?

17 A That was done to support the application, yes.

18 Q All right, sir. Good. And since then, and since you've
19 been in your current position, SCE&G has continued to
20 analyze its staffing needs under its Base Load Review
21 order, correct?

22 A It would be imprudent not to do that.

23 Q All right. And so you are here today seeking another
24 \$72.3 million under your Base Load order for additional
25 staffing concerns, correct?

1 A The way I characterize that is that, as we progress and
2 learn more about the changing environment -- and as Mr.
3 Marsh and Mr. Byrne both testified to -- there was an
4 initial sum of money -- that being what we previously
5 referred to as contingency fund -- which was part of
6 what we'd utilize for known conditions that we
7 recognized would be changing and was defined as a
8 regulatory risk. So that money was allocated. As you
9 have identified, the Supreme Court disallowed that,
10 provided that we would come back and justify those
11 specific -- and quantify those specific dollar amounts.

12 Part of my charge when I came in in 2010 was to
13 perform that level of review and justification that
14 would specifically identify those material costs and
15 include those as a line-item basis. That as not only
16 done with personnel; it was also done for materials.

17 Q All right. So, it sounds -- I guess you all really
18 relied on that contingency fund to fill out some of the
19 gaps here, in your plan, weren't you?

20 A Well, whenever you look at a project of this magnitude,
21 the reasonable and prudent thing to do is to look ahead,
22 identify risk, and as I understand it, the Commission
23 requires in the initial filing that we identify what are
24 the potential risks. Those were identified,
25 characterized, and there was funding that was provided

1 that would adjust for that. When that funding was
2 statutorily removed, with the consideration that we come
3 back and identify those specifically, that is what the
4 company has then pursued.

5 **Q** Well, when you assumed your current responsibilities and
6 you made this review that you've described here, and
7 that you described in your response to my data request,
8 did you find any documentation that suggested that
9 staffing costs needn't be specific because you could put
10 them in your contingency fund?

11 **A** Could you repeat that, to make --

12 **Q** Yeah. Did you --

13 **A** -- sure I understand it?

14 **Q** Yeah. When you were -- you know, you did a -- you said
15 when you took your current position --

16 **A** Correct.

17 **Q** -- and you started then identifying staffing concerns,
18 needs, that you went back and looked at what the staff
19 before you had put together, to analyze the staffing
20 needs. Have I fairly characterized that?

21 **A** Yes, you have.

22 **Q** And what I understand you to say -- and I really kind of
23 understood everybody else to say -- is that these costs
24 that you're asking for, that you're here supporting
25 today, would have come out of the contingency fund, had

1 the Court permitted you to have a contingency fund. Is
2 that a fair characterization?

3 A That is a fair characterization.

4 Q And so my question to you is, did you -- and when you --
5 you know, you went through -- I'm sure you were very
6 thorough, and went through mounds of paperwork in
7 reviewing this matter going back to the 2008 application
8 and these studies that you've described. Did you find
9 any document in what you reviewed that indicated that
10 the staffing costs -- future staffing costs -- could
11 come out of the contingency fund?

12 A I don't think I'd find that for a number of things. I
13 think the characterization is that there is an
14 allocation that will be utilized to address the risks
15 that were identified in the original submittal, and as
16 we evaluated what the staff size was, how it was
17 derived, what are the changing environments, what are
18 the changing regulatory concerns, that those by
19 definition would be allocated through the contingency
20 fund.

21 Q And so you're here -- your testimony sponsors \$72
22 million, correct?

23 A 72.3.

24 Q Thank you. Now, you also allude to the last docket in
25 this matter. It was a 2010 docket. It was 2010-376-E.

1 refiled. I can't address that. I wouldn't characterize
2 it the way you just did.

3 **Q** All right. Well, fair enough. Now, it took you from
4 May 16 to February 29 to find another \$72.3 million,
5 correct?

6 **A** No, not correct.

7 **Q** Tell me -- less time? Did you find it in less time than
8 that? When did you start evaluating -- after the May
9 16, 2011, order, when did you start evaluating your
10 additional staffing needs?

11 **A** Well, I didn't find anything, specifically. I did what
12 I think -- I did what my responsibilities are, and that
13 is to continually evaluate what's going on in the
14 industry; where we are, relative to staffing levels; and
15 then make adjustments accordingly. And, as has been
16 identified to me, through our transparency issues with
17 the Public Service Commission, it was incumbent on us to
18 identify potentially anything that we might see as the
19 need for an increase to the Commission. So as I saw the
20 changing environment and issues associated with that, we
21 modified the staffing plan, as discussed in my direct
22 testimony, and that is being presented today.

23 **Q** Thank you. Thank you. And because you're continually
24 looking, analyzing your staffing needs, you're aware
25 sitting here today of additional staffing needs that you

1 will have to ask this Commission for at a future date,
2 aren't you?

3 A Well, let me explain to you that specifically in the
4 testimony I talk about the fact that Fukushima rules are
5 not complete at this time. We are acting with, I think,
6 prudence on what we know at this time will be required.
7 My -- so that's what we're doing at this moment. We're
8 evaluating the current needs and identifying testimony
9 that, should those rules require additional resources,
10 then we would be mandated to adjust that staffing plan
11 and present it accordingly.

12 Q All right. And so the Fukushima rules would account for
13 how many additional positions, based on your analysis of
14 the draft and the process to date?

15 A Our current state --

16 Q Yes, sir.

17 A -- today?

18 Q Yeah.

19 A Today, our current analysis for what is currently
20 required is 40 personnel.

21 Q All right. So you know that you're coming back in for
22 40 personnel, sitting here today.

23 A Oh, no, that's not correct. I apologize. We are asking
24 for 40 personnel as part of this testimony. As far as
25 looking forward, I can't predict that. I have -- that

1 would be like looking into a crystal ball. I can't
2 predict regulation. I don't know what the NRC's going
3 to identify, relative to new requirements.

4 We try to stay current with that. We have users'
5 groups, we meet with the NRC periodically. So, we try
6 to understand where the rulemaking is headed, and adjust
7 accordingly. But to predict a specific number generally
8 requires a specific analysis. So until that analysis is
9 complete, I would not speculate on what that number
10 would be.

11 Q So I misunderstood. You're not continually analyzing
12 this; you've not made an analysis of your future
13 staffing needs at this time, beyond what you're
14 supporting here in your --

15 A No, that's not correct. What I said earlier is correct.
16 What I said earlier was we continually evaluate and
17 analyze. When I clearly understand what a change
18 requirement would require me to do, then we would
19 institute that requirement. We would codify it, we
20 would include it in our documentation, then we would
21 submit that before the Commission.

22 Q All right. So we can expect to see you back in
23 sometime, can't we, sir?

24 A I don't predict the future. Should that occur, then
25 I'll be back here.

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1 available to respond to a fire, should it occur. They
2 are allowed to rely on the emergency response team,
3 which can be called in, and there are requirements
4 associated with that, and they are very specific. So
5 they have the ability, if the fire or the -- whatever
6 the natural event -- occurs, if that expands into a
7 longer period of time, they are able to take credit for
8 the emergency responders to be coming to the site, as
9 well as the local firefighting department that would be
10 able to arrive in certain timelines that are
11 predescribed.

12 Subsequent to the Fukushima event, the Nuclear
13 Regulatory Commission -- and I think appropriately so,
14 if you look at what makes sense and what prudence would
15 have, based on those events -- have asked the utilities
16 to analyze, assess, and be prepared to -- which we are
17 doing -- address a multiunit event. That is something
18 that we had not yet -- had not predicted from a
19 probability perspective. So when you look at having an
20 individual site be prepared for a multiunit casualty,
21 the rules are very specific in that, number one, the
22 site now has to stand alone for six hours where, in the
23 past, you could rely on emergency responders that would
24 be there sooner than that. So that's a change in the
25 criteria, so we have to change how we model that. They

1 guess was, I think we're in a good position and a good
2 posture not to require -- I'm going to use the term -- a
3 significant amount of additional resource.

4 Now, that being said, it will require a specific
5 and detailed analysis, and that's why I think it's not
6 prudent for me to say I will never have to raise that
7 number that is identified currently, but I think we've
8 done a very good job of evaluating what we think is
9 going to be appropriate and reasonable to respond to a
10 potential rulemaking that will be coming out.

11 Q And you still think that time is about two years out,
12 before you have the final rulemaking?

13 A Before we would have the final rulemaking, that's
14 correct.

15 COMMISSIONER WHITFIELD: Yes, sir. Thank you,
16 Mr. Lavigne. That's all I have, Mr. Chairman.

17 CHAIRMAN WRIGHT: Commissioner Howard.

18 EXAMINATION

19 BY COMMISSIONER HOWARD:

20 Q Mr. Lavigne, I've got to admit I've got a lot of
21 problems understanding this whole concept about
22 additional staffing, and my problems are all over the
23 place. The first thing, I look at the number. Then I
24 look at the position the plant is now, the site is now.
25 And then I see what's delaying the schedule. And I

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1 guess I'm concerned about us paying for staffing -- and
2 then Santee Cooper plays into it. It just seems to me
3 like an awful lot of people that we don't need. And I
4 admit, my resume does not include operating a nuclear
5 plant, or building one, so -- but just sort of -- just
6 someplace to start off would be on Chart B. You've got
7 an FTE change, and look down at the timing there.
8 You've got an FTE change of three full-time employees
9 for \$15 million. That's \$5 million per additional
10 employee. That is incomprehensible to me, and I'm sure
11 there's something that I don't realize.

12 A Yeah, as identified on that page, I would -- I
13 appreciate where you're coming from. Let me try to
14 explain that -- or, let me explain that. We added three
15 additional -- what I would call -- bodies, or three
16 additional staff. The timing variance relates to people
17 that are in maintenance, chemistry, outage planning and
18 scheduling, so the total number of those personnel is
19 about 180 to 190. That is the number that we had to
20 shift, from a timing perspective, and instead of
21 bringing them in in 2013, '14, or 2015, we moved the
22 timeline and we're bringing them in earlier, to have
23 them trained and qualified and available to support the
24 units. So it's bringing -- the earlier hiring of those
25 personnel is what has driven that.

1 One of the things that being a new plant design,
2 new plant construction, this has not been done -- as has
3 been pointed out -- in 20 or 30 years. Actually, about
4 30 years now. So the Institute of Nuclear Power
5 Operations, who we have committed to from a training
6 perspective, this is new to them as well. So the
7 training requirements are being generated, and we're all
8 developing those as we go, and our interaction with the
9 Institute of Nuclear Power Operations, as well as the
10 Nuclear Regulatory Commission, relative to training, is
11 that they want to see trained, qualified people earlier
12 than what I think was originally anticipated.

13 So because of those changes, and to be able to
14 support our -- we have an accreditation process, just
15 like a university, and it's done through the Institute
16 of Nuclear Power Operations. So they have to come to
17 our facility, validate that we're capable of delivering
18 the training in accordance with a systematic approach to
19 the training process, and then verify that all our
20 training materials have been generated, that the
21 training has been completed. To do that, the
22 individuals -- or what we call incumbents -- that have
23 to come in and create training materials, the first
24 thing they do is look at all of the technical manuals
25 and the equipment that's associated with that, and they

1 generate the procedures that they will be performing the
2 maintenance and work activities associated with those
3 pieces of equipment in the plant. From that, training
4 materials are developed.

5 So this whole process, from a timeline perspective,
6 we've adjusted the timeline. So we moved those 180 or
7 so resources back, anywhere from one to three years, and
8 that's where you see the \$15 million. It's not in the
9 three full-time equivalents; it's in the totality of
10 moving those resources, or bringing them in earlier to
11 support the development of the specific maintenance
12 procedures and training materials, and actually conduct
13 the training and have them qualified before we would
14 load fuel into the units.

15 Q I guess I'm still confused on the fact that you're
16 bringing in people earlier, yet we're delaying the start
17 by a year, or whatever the case may be. Eleven months,
18 I think that would be.

19 A We are also bringing Unit 3 back --

20 Q So we've got people on the payroll for, now, it'll be
21 three years that, in essence, are not doing anything,
22 except studying and training.

23 A As I indicated earlier, if they were just doing that,
24 they wouldn't be in today. That would be imprudent for
25 me to do that. I would not -- I would not support that,

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1 personally. So what they're doing is, as I indicated
2 earlier, they're doing evaluations and reviews of the
3 equipment that's coming on-site, reviewing the technical
4 manuals and information associated with that equipment,
5 writing procedures associated with that equipment. Then
6 they'll begin the training process. So it's a
7 sequencing evolution that has to occur, and those
8 sequences all have to line up with the milestones that
9 we've identified in the schedule.

10 Q And, likewise, Santee Cooper has the same people doing
11 the same thing?

12 A No. In this case, Santee Cooper has -- through
13 oversight, they evaluate what we do and support that.
14 So they've given us responsibility to operate and
15 maintain the units, with their oversight.

16 Q And do the subcontractors have some responsibilities for
17 this training for their employees, or do they not?

18 A The subcontractors are trained separately and specific
19 to construction, not related to the operation of the
20 units. What's been described here is related
21 specifically to the operating unit.

22 Q I guess going back to emergency service and health
23 physics -- and I still just don't get it. Seems like
24 we've got -- the order allowed 48. Now we've got a
25 staff proposal of 88 and then an additional 40. What

1 are these people doing when they come to work? I mean,
2 you got 100-and-some people coming to work, just in the
3 emergency planning and health physics? When they walk
4 on the site at Jenkinsville, what do they do in the
5 course of the day?

6 A Well, the firefighter portion of that, they're actually
7 going to be performing -- in the course of a routine
8 day, there's a number of activities that have to be
9 performed. We've got three units, and there's a lot of
10 fire protection testing that has to be completed. All
11 of the headers have to be verified; all fire
12 extinguishers have to be verified. They have to verify
13 the sprinkler system is appropriate and operational.
14 And so there's a detailed set of procedures that they
15 have to implement, and they will be doing that when
16 they're not responding to a given event.

17 The health physics personnel, as identified
18 earlier, they'll be coming in and performing a number of
19 activities, as they do today. There are routine surveys
20 that they're conducting; they're responsible for the
21 transfer of all the liquids within the plant. So they
22 have that function that they do, as well. So we're
23 trying to give them -- not trying to. They have job
24 functions that they do during the course of the day.

25 They review all of the -- Mr. Byrne referred to

1 this in his testimony. You have now three separate what
2 we call radiologically controlled areas, for three
3 separate units, so they individually have to be
4 evaluated and monitored. So these individuals, when
5 they come in during the day, they will be out in the
6 plant doing radiation surveys and identifying what the
7 various levels of contamination are, or are not, in
8 various areas. And they will post that information, so
9 a general worker knows what any potential issues might
10 be.

11 In addition, they work on all of the -- as
12 maintenance work is done, they review all of that work
13 to verify the radiological conditions and do -- perform
14 their role in supporting the protection of those
15 individuals working in a radiologically controlled
16 environment. So they determine what their clothing
17 requirements are, and things of that nature. So they
18 evaluate that during the course of a day.

19 In addition, they deal with all of our -- what we
20 call -- resin transfers, where you move anything liquid
21 from one part of the plant to the other. They're
22 responsible for those activities, and will continue to
23 do those.

24 But we've had to segregate the specific things
25 that, should you have an event or emergency, those

1 personnel no longer can move from one plant to the
2 other, as we used to be able to do. So we've had to
3 dedicate -- and I'm going to use the term -- additional
4 resources, to do that.

5 So they have lots of activities to do during the
6 day, but we are careful to assign duties that, should we
7 have an event, that they no longer have to perform that
8 event -- perform that function. As in a maintenance
9 person today, he has fire protection responsibility,
10 we'll be removing that from him. So he'll still be
11 doing maintenance work; he just won't be available to do
12 the fire protection portion. So the fire protection
13 personnel will be performing that duty in an emergency
14 event. As well, during the day, we'll have him to pick
15 up some of the testing and maintenance functions.

16 There was a net decrease in the number of
17 maintenance personnel at the station, and that was
18 identified because of some of these other activities as
19 being picked up, as an example, through fire protection.
20 We actually reduced the number of maintenance personnel
21 by 16, from the previous proposal.

22 Q Okay. I guess this caught my eye: The variance in FTEs
23 appears to change. For example, emergency planning,
24 that averages out to \$147,000 per FTE. Like I said, the
25 training is \$5 million. Overall, the 124 -- not

1 counting security contractors -- is \$66.2 million;
2 that's \$533,000 per FTE. I mean, that number to me just
3 seems high. I'm sure there's a lot of that you
4 explained about that I probably don't know, but it just
5 seems, off the cuff, \$533,000 in additional full-time
6 employees.

7 A Well, unfortunately, it's --

8 Q It just seems like --

9 A -- not a straight-line comparison. It looks at the
10 fully loaded cost associated with those individuals,
11 what we have to do to bring them in and support the
12 contract. These are -- the security, specifically, it's
13 contract personnel versus what they call regular full-
14 time employees.

15 COMMISSIONER HOWARD: Okay, thank you.

16 CHAIRMAN WRIGHT: Commissioner Mitchell.

17 EXAMINATION

18 BY VICE CHAIRMAN MITCHELL:

19 Q How you doing, Mr. Lavigne?

20 A Fine, thank you.

21 Q Making it okay? This is a little bit along the line of
22 the questions of Commissioner Howard. Do you see that
23 the Fukushima accident -- and you were speaking there
24 earlier as far as the operators, their tests changing,
25 and the tests seemingly getting harder and harder where

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1 it was very hard to keep qualified operators. Do you --
2 in your rationale, did that accident maybe bring on
3 tougher operation schedules or -- and cover training for
4 these new operators? Do you think that's affected the
5 safety climate whatsoever?

6 A No. I don't think that's affected the licensed operator
7 exams. I think the NRC has been on a -- the Nuclear
8 Regulatory Commission -- has been on a progressive
9 review of those examinations and how they're delivered.
10 They're just -- and I use the term -- raising the
11 standard, and we're adjusting to that standard as we
12 move forward.

13 The Fukushima events, they related more to tasks
14 that are required to be performed. It doesn't really
15 change the knowledge base. They've added additional
16 tasks for what we would call a response to an emergency
17 event. So there are more things that we need to be able
18 to respond to and take care of, during an emergency
19 event, and that's why we've committed the dedicated
20 resources to accomplish those functions.

21 Q So they wouldn't have directly related at all to your
22 employment of FTEs?

23 A Not the operator area, no.

24 Q No effect?

25 A No effect.

1 **VICE CHAIRMAN MITCHELL:** Thank you. That's
2 all I have, Mr. Chairman.

3 **CHAIRMAN WRIGHT:** Commissioner Fleming.

4 **EXAMINATION**

5 **BY COMMISSIONER FLEMING:**

6 **Q** Good morning.

7 **A** Good morning.

8 **Q** I wanted to go -- continue with the staff issue. My
9 concern is finding the qualified staff. And you've
10 already alluded to -- the requirements are getting
11 stricter and stricter, and the tests are becoming much
12 more -- sounds like -- more critical for employee type
13 questions. Which you certainly, I think, would agree
14 that's important, to have someone who thinks critically
15 in those positions. But with those stricter
16 qualifications, are there enough qualified people out
17 there to fulfill those positions? And does the fact
18 that there's been such a long time, with nuclear power
19 in the forefront again -- some would disagree that it's
20 in the forefront again -- that the need is there again,
21 and the educational and training resources have lapsed
22 for a period of time, are there enough qualified people
23 out there to fill these positions?

24 **A** Well, I would be remiss if I said it was not a
25 challenge. It is. For that reason, several years ago

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1 the company -- I think, in an appropriate move -- has
2 worked with a number of the local technical colleges.
3 We have a specific program associated with Midlands
4 Tech, Aiken Tech, Orangeburg, and others, that are
5 deploying specific programs related to the nuclear
6 application. The Institute of Nuclear Power Operations
7 has developed the standard -- it's called the Nuclear
8 Uniform Curriculum Program -- and if personnel come out
9 of the technical colleges meeting those requirements,
10 then they will come in at a higher level and we're able
11 to utilize them in the operating environment.

12 So we are acquiring personnel -- in fact, we've had
13 a number of recent graduates that we've hired and
14 brought into our staff. And we'll take them, with that
15 base level of knowledge, and put them through our
16 rigorous training programs to be able to produce
17 qualified candidates. We are also still being able to
18 recruit from the Navy. Even though the numbers are
19 less, we're still able to do that. So, in aggregate,
20 even though it's a challenge, I think we're going to be
21 able to meet the timelines. That's why we have moved
22 some of those back, to allow more time to get them
23 trained and qualified.

24 As an example, with Midlands Tech students, we
25 recognize that, even though they came out of the

1 technical school, a program dedicated to the Nuclear
2 Uniform Curriculum, they still weren't at the standard
3 that we think is appropriate to operate a nuclear plant.
4 So when they first come on-site, we give them a six-week
5 indoctrination program and walk them through what a
6 nuclear power application is all about, and refresh them
7 on fundamentals: How they operate a valve, what are the
8 components, how does the turbine really operate. So we
9 give them a lot of very -- I'll call it -- high-level
10 knowledge, but that prepares them, say, when they go to
11 this operator class, that they'll be much better
12 equipped to be successful.

13 It kind of goes to the heart of what we discussed
14 earlier: In the training regimen, we know we need to do
15 more to give them a higher level of instruction on the
16 front end, so we incorporated that into the program.
17 That has required us to extend those timelines. That's
18 why we're bringing them in earlier, to assure that
19 coming out of the pipeline -- we'll call it a pipeline
20 -- at the end of the training program, we'll have enough
21 success to have licensed candidates who can pass the
22 Nuclear Regulatory Commission license requirements.

23 Q Are you doing -- or, are the technical colleges doing
24 like aptitude testing to see if the people that are
25 applying right up-front have the aptitude to really do

1 the specifics?

2 A I apologize, I don't know the answer to that question.
3 I do know that we, through -- there's a board on which
4 we have several members on that board that look at how
5 Midlands Tech and other local colleges are doing. In
6 the process of doing that, they continually make
7 recommendations to the schools as to how they can -- and
8 I'd use the term -- better serve our needs, and they've
9 been very responsive to this.

10 Q It just seems like it would provide an efficiency to the
11 process, to give you the people -- starting out with
12 people with the right aptitude.

13 A Well, I appreciate that. What I'll do is, based on what
14 you've identified -- our plant manager at Unit 1 is on
15 the advisory board, and I'll speak to him about is there
16 something we can work with, with Midlands and the other
17 Programs on, and see if they can support that.

18 Q Well, I wasn't doing it as a recommendation, but just --

19 A I appreciate that.

20 Q I was just curious if that's being done, to kind of
21 provide efficiency, as well.

22 A Well, I'll try and --

23 Q And less frustration to a student that's not -- that
24 really doesn't have the aptitude for it.

25 And I wanted to go back to this Lake Charles thing.

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1 I know it was discussed a bit earlier. I am concerned
2 about -- I mean, that really does concern me, that the
3 quality there -- it sounds like you're really putting
4 the staff, the quality assurance staff, there, to really
5 stay on top of it to make sure it's done. But it is
6 adding a layer of cost to the project, for this
7 particular project. Do you have an idea of what that
8 cost is -- the additional cost -- to make sure that Shaw
9 is giving a product that meets the qualifications and
10 standards you need?

11 A I could not do that just for the Shaw facility. I mean,
12 overall for the project, we're adding 26 additional
13 full-time equivalents at a price updated to \$6 million.
14 So if I characterize it just from a cost perspective, I
15 would say that the increased oversight, that's the cost
16 that I would attribute to it.

17 Q But I thought this was the supplier that has been the
18 most challenging.

19 A I personally have not quantified that cost. That would
20 be much less than that. If I just -- we tend to -- we
21 had a full-time resident there for a period of time, and
22 we are doing additional oversight. So if I -- I can do
23 a seat-of-the-pants calculation that would put it at
24 about two full-time equivalents.

25 And I think that will stop and be reduced to about

1 a half of a full-time equivalent, over the next four or
2 five months, because of the improvements that have been
3 seen through the efforts of that group, as well as, as
4 Mr. Byrne and Mr. Marsh pointed out, they both
5 personally have spent time at SMS to impress upon that
6 vendor the need to improve the overall quality. So, the
7 level of engagement has been very, very significant.
8 It's been at the highest levels of the company.

9 And about -- I'm going to say -- six months to a
10 year ago, we imported -- I'll say import -- we actually
11 moved one of our long-term managers in Quality at Unit 1
12 over to Unit 2-3, so that he could give this a much more
13 aggressive insight and look, and we're seeing positive
14 results from that.

15 Q Well, and it certainly sounds like, on your end, you are
16 doing everything humanly possible --

17 A Well, we --

18 Q -- to improve what's going on on the other end.

19 A I know it sounds very negative, relative to Shaw and
20 what they've done at the facility, but it's hard for me
21 to sometimes give credit where credit is due, in this
22 case, but the reality is they have learned a number of
23 lessons. They have genuinely turned around their
24 production capability.

25 Q Are they going to pay you for that expertise? That

1 might be a way -- I'm just being facetious.

2 A I don't think that's coming.

3 [Laughter]

4 Q I mean -- well, I do think that -- like I said, I
5 appreciate -- it sounds like you all, SCE&G, is making
6 every effort possible to bring the quality up.

7 Just for clarification, you said that the personnel
8 are hired by SCE&G, and Santee Cooper has an oversight
9 position of that personnel. How does that relate to the
10 cost? Do they pay 45 -- will there be 45 percent more
11 added onto the cost of the personnel, from Santee
12 Cooper?

13 A Well, the staffing numbers identified here are the 55
14 percent numbers. So they would just -- they would be
15 providing a prorated share for the 100 percent number
16 for these full-time equivalents.

17 Q Okay. So the staffing amount is just for SCE&G, and --

18 A Yeah.

19 Q -- then you add the additional amount for Santee Cooper.

20 A That would be correct, the additional 45 percent. But
21 the numbers won't change.

22 Q Okay. I didn't know whether they made that difference
23 up in a different -- or are paying you for that.

24 A That's correct.

25 Q All right. Well, thank you.

1 A Thank you.

2 CHAIRMAN WRIGHT: Commissioners. Commissioner
3 Hall.

4 COMMISSIONER HALL: Thank you, sir.

5 EXAMINATION

6 BY COMMISSIONER HALL:

7 Q Good morning, sir. I just have a -- just a clarifying
8 question about the fire brigade. So, my understanding
9 is that, before, people had ancillary duties for
10 firefighting. So, will they be -- those people will be
11 moved to their primary function? Or will you hire new
12 people? I'm just trying to understand that.

13 A We will be hiring a number of new people.

14 Q Okay.

15 A The personnel that would be performing maintenance
16 activities, as an example, we still need that number.
17 That's why we were able to see a reduction in the
18 Maintenance Department of 16, overall. So in all these
19 aggregate numbers that we've been talking about, there
20 were some reductions. I know they don't get talked
21 about much, but we actually did some reductions. And we
22 reduced the number of maintenance personnel by 16,
23 because some of those functions will be performed by the
24 fire brigade personnel who -- as is aptly pointed out --
25 we're not going to just have them -- I mean, there will

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1 be some downtime, but we're going to keep that to an
2 absolute minimum.

3 COMMISSIONER HALL: Okay. Thank you.

4 CHAIRMAN WRIGHT: Thank you. Any other
5 questions, Commissioners?

6 [No response]

7 Mr. Gissendanner?

8 MR. GISSENDANNER: We have no redirect of Mr.
9 Lavigne. We'd ask the witness be excused.

10 CHAIRMAN WRIGHT: You may be excused.

11 [WHEREUPON, the witness was excused.]

12 Okay. We're going to take a break now. We'll
13 come back at 11:20.

14 [WHEREUPON, a recess was taken from 11:10
15 to 11:20 a.m.]

16 CHAIRMAN WRIGHT: Be seated please. We are
17 going to resume the hearing, and I believe now
18 we're ready to call your next witness.

19 MR. BURGESS: SCE&G calls Hubert Young to the
20 stand.

21 [Witness sworn]

22 THEREUPON came,

23 H U B E R T C . Y O U N G , I I I ,
24 called as a witness on behalf of the Petitioner, South
25 Carolina Electric & Gas Company, who, having been first duly

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1 sworn, was examined and testified as follows:

2 **DIRECT EXAMINATION**

3 **BY MR. BURGESS:**

4 **Q** Could you please state your name for the record?

5 **A** My name is Hubert Young.

6 **Q** And by whom are you employed and in what capacity?

7 **A** I'm employed by South Carolina Electric & Gas. I'm the
8 manager of Transmission Planning.

9 **Q** Mr. Young, have you prepared or caused to be prepared
10 under your direct supervision 28 pages of direct
11 testimony, which has been prefiled in this docket?

12 **A** I did.

13 **Q** Do you have any changes or corrections that you'd like
14 to make to your testimony?

15 **A** I do not.

16 **Q** If I asked you the same questions in your testimony,
17 would your answers be the same today?

18 **A** They would.

19 **MR. BURGESS:** Mr. Chairman, at this time, we
20 would move into the evidence of record the prefiled
21 direct testimony of Clay Young, as if given orally
22 from the stand.

23 **CHAIRMAN WRIGHT:** Mr. Young's direct testimony
24 will be entered into the record as if given orally
25 from the stand.

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[See pgs 638-665]

MR. BURGESS: Thank you.

BY MR. BURGESS:

Q Mr. Young, have you also attached exhibits to your direct testimony?

A I have.

Q And are there any changes or corrections you'd like to make to your exhibits?

A No.

MR. BURGESS: Mr. Chairman, we'd like to move into the record the prefiled direct testimony exhibits of Clay Young. They are identified as HCY-1 and HCY-2, and we would ask they be marked as the next hearing composite exhibit.

CHAIRMAN WRIGHT: Mr. Young's two exhibits will be entered as a composite exhibit, into the evidence of the case, and it will be Exhibit No. 5.

[WHEREUPON, Hearing Exhibit No. 5 was marked and received in evidence.]

MR. BURGESS: Thank you, Mr. Chairman.

BY MR. BURGESS:

Q Mr. Young, have you prepared a summary of your direct testimony?

A I have.

Q Would you please deliver that at this time?

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1 A I will. Good morning, Mr. Chairman and members of the
2 Commission. The purpose of my testimony is to present
3 information related to adjustments to the transmission
4 construction cost forecast.

5 Those updates total \$7.9 million. They represent
6 an increase of approximately 2½ percent in the
7 transmission cost forecast, of the \$322 million
8 previously approved. These adjustments fall into five
9 categories:

10 The first is the decision to construct a new Saluda
11 River Transmission, or SRT, Substation. The original
12 plan for routing power from Unit 2 involved constructing
13 additional transformers at both the Lake Murray and the
14 Denny Terrace Substations. Subsequent studies indicated
15 that this alternative requires another transformer at
16 the Lyles 230/115 kV Substation and three 115 kV line
17 improvements.

18 Two factors coincided that caused the change in the
19 plan. First, it was determined that the existing Lake
20 Murray and Denny Terrace Substations were too small to
21 accommodate these additional transformers; new
22 substations alongside these existing substations would
23 be required. Constructing the new substations increased
24 the cost of the original plan from \$13.9 million to
25 \$27.8 million. Second, the decision to construct the

1 V.C. Summer to St. George lines on existing rights-of-
2 way routed the lines directly through the Irmo,
3 Lexington, and West Columbia areas. These are areas
4 where new transformer capability is needed and where the
5 original plan intended to deliver power.

6 Studies were conducted after the decision was made
7 to use existing rights-of-way; they determined that
8 building the SRT Substation was a lower-cost alternative
9 than was available -- and was available and feasible.
10 The cost of the SRT Substation and related improvements
11 is \$15.5 million, which represents an increase of only
12 \$1.6 million from the original forecast.

13 Locating the new substation at this site will also
14 make a greater contribution to system reliability and
15 efficiency than other alternatives. The projected in-
16 service date for the SRT Substation is May 31, 2015.

17 The location of the substation is shown on Exhibit
18 HCY-2 to my direct testimony. It will be located on
19 approximately 50 acres in Lexington County, of which
20 approximately 15 acres will be cleared, while the
21 remainder will remain wooded to provide screening of the
22 substation from the surrounding area.

23 A second adjustment in the cost forecast results
24 from SCE&G's decision to underground a section of the
25 existing Parr/V.C. Summer safeguard 115 kV line, and to

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1 lower the Parr/Midway 115 kV lines. The reliability of
2 the Parr/V.C. Summer safeguard 115 kV line is critical
3 to the safe operation of Unit 1. The safeguard line
4 provides backup power to that unit. The Parr/V.C.
5 Summer line currently crosses over one 230 kV line and
6 two 115 kV lines. Once construction of the new
7 switchyard and new 230 kV transmission lines is
8 completed, the Parr/V.C. Summer line will cross over
9 five 230 kV lines. If a pole or insulator supporting
10 the Parr/V.C. Summer line were to fail at the site of
11 the crossing, the safeguard line could come into contact
12 with the five 230 kV lines, causing all these lines to
13 be removed from service. This could cause loss of the
14 safeguard line and a major event on the system that
15 could result in loss of service to a large number of
16 customers.

17 The cost to underground this section of the line is
18 approximately \$2.9 million. The updated forecast
19 reflects that amount.

20 Additional design of the lines serving the new
21 units have resulted in seven 230 kV lines crossing the
22 Parr/Midway 115 kV lines. The lines must be lowered in
23 order to meet National Electric Safety Code crossing
24 clearance standards at this crossing. The cost to lower
25 the lines is approximately \$704,000.

1 Additional design and engineering refinements have
2 also demonstrated that SCE&G must also replace a bus-
3 side disconnect switch in the V.C. Summer Switchyard #1
4 because it presently does not have the power current
5 rating necessary to function properly when the units
6 become operational. The estimated cost associated with
7 this work is \$614,000.

8 Additionally, design and engineering refinements
9 have shown that SCE&G must make improvements to busses
10 and terminals at three of its existing substations, to
11 interconnect upgraded transmission lines in a safe and
12 reliable manner. The cost of this work is approximately
13 \$2.1 million.

14 SCE&G has continued the purchase of real property
15 and rights-of-way to construct the Blythewood/Killian
16 segment of the V.C. Summer/Killian line and has settled
17 claims made by Richland County and the Town of
18 Blythewood related to the siting of the 230 kV line.
19 The Blythewood/Killian segment of the V.C.
20 Summer/Killian 230 kV line is the only portion of the
21 line serving the new units that will be constructed
22 along new rights-of-way. When the initial transmission
23 cost forecasts were done, the exact route of this
24 segment was not known. The fair market value for
25 property along the actual route is higher than the

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1 forecasted value by approximately \$369,000. Some
2 condemnations are still in progress, so this cost could
3 increase, based on the results of those proceedings.

4 Last year, SCE&G entered into a settlement
5 agreement -- settlement agreements Richland County and
6 the Town of Blythewood, related to siting of the line
7 and, in the case of the County, payment for rights-of-
8 way. The settlement -- the settlements avoid the cost
9 of alternatives, which were rerouting and undergrounding
10 portions of the line.

11 Lastly, in my testimony, I discuss adjustments
12 related to reallocation of costs between SCE&G and
13 Santee Cooper. SCE&G and Santee Cooper are joint owners
14 of the units, as well as the V.C. Summer Switchyard #1
15 and the V.C. Summer Switchyard #2. Recently, the two
16 owners agreed to a new methodology for allocating costs
17 associated with these assets. Rather than assigning
18 individual terminals, switches, and other items of
19 property between the two companies, they decided to
20 divide the full cost of each switchyard based upon a
21 percentage reflecting each company's use of the
22 equipment. As a result, SCE&G's share of the
23 transmission costs decreased. The estimated impact of
24 this adjustment is a decrease in the transmission
25 construction cost forecast of \$1.4 million.

1 All of the adjustments that I discuss in my direct
2 testimony are reasonable and prudent costs that are
3 necessary to construct the transmission lines associated
4 with the units. I would urge the Commission to adopt
5 the transmission cost adjustments, as proposed in this
6 petition.

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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY OF HUBERT C.
25 YOUNG, III, FOLLOWS AT PGS 638-665]

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PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1 **DIRECT TESTIMONY OF**
2 **HUBERT C. YOUNG, III**
3 **ON BEHALF OF**
4 **SOUTH CAROLINA ELECTRIC & GAS COMPANY**
5 **DOCKET NO. 2012-203-E**
6

7 **Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.**

8 A. My name is Hubert C. Young, III. My business address is 601 Old Taylor
9 Road, Mail Code J37, Cayce, South Carolina 29033. I am employed by South
10 Carolina Electric & Gas Company ("SCE&G" or "Company") where I am the
11 Manager of Transmission Planning.

12 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND BUSINESS**
13 **BACKGROUND.**

14 A. I am a graduate of Clemson University with a Bachelor of Science degree in
15 Electrical and Computer Engineering. I am a registered Professional Engineer in the
16 State of South Carolina.

17 I began working for SCE&G in 1975. During my thirty-seven years of
18 service with the Company, I have held a number of positions in the Engineering
19 Computer Support Department and Transmission Planning. In 1993, I was promoted
20 to my current position of Manager of Transmission Planning.
21

1 Q. ARE YOU A MEMBER OF ANY INDUSTRY COMMITTEES FOR
2 SYSTEM RELIABILITY ASSESSMENT OR PLANNING?

3 A. Yes, I am currently Chairman of the SERC Reliability Corporation (formerly
4 known as the Southeastern Electric Reliability Council and hereinafter referred to as
5 "SERC") Engineering Committee. Additionally, I am a member of the North
6 American Electric Reliability Corporation ("NERC") Planning Committee, the
7 NERC Reliability Assessment Subcommittee, the Carolinas Transmission Planning
8 Coordination Agreement Principal Planners Committee, the Eastern Interconnection
9 Planning Collaborative ("EIPC") Technical Committee, and the EIPC Stakeholder
10 Steering Committee Transmission Owner Caucus. I am also a member of various
11 other committees related to transmission planning.

12 Integrating the transmission facilities of various entities across the United
13 States is an important function of transmission planning and cannot be accomplished
14 without collaboration. As a result, all these committees are directly involved with
15 assessing the current and future capabilities of the integrated transmission grid in
16 North America, the Southeast, and the Virginia/Carolinas or setting reliability
17 standards for the electric power industry. Accordingly, it is critical that SCE&G
18 actively participate on these committees so that its interests along with the interests
19 of its customers are adequately represented.

20

21

1 **Q. PLEASE SUMMARIZE YOUR DUTIES AS MANAGER OF**
2 **TRANSMISSION PLANNING AT SCE&G.**

3 A. I oversee the planning and associated analyses of the SCE&G electric
4 transmission system and all interconnection transmission facilities with
5 neighboring utilities. The goal of transmission planning at SCE&G is to ensure
6 reliable and cost effective delivery of electric power to SCE&G customers while
7 developing and maintaining strategically supportive infrastructure to sustain and
8 further South Carolina's economic development and the Company's financial
9 integrity.

10 **Q. HAVE YOU EVER TESTIFIED BEFORE THE PUBLIC SERVICE**
11 **COMMISSION OF SOUTH CAROLINA ("COMMISSION")?**

12 A. Yes, I have testified before the Commission on many occasions. Recently,
13 I testified in Docket No. 2011-325-E in which I discussed with the Commission the
14 need and necessity for the construction of the new VCS1-Killian 230 kilovolt ("kV")
15 Line, the new VCS2-Lake Murray 230 kV Line No. 2, and a segment of the new
16 VCS2-St. George 230 kV Line No. 1 ("Segment of VCS2-St. George 230 kV Line
17 No. 1") that runs alongside the VCS2-Lake Murray 230 kV Line No. 2 from the
18 Company's V.C. Summer Switchyard #2 to the Lake Murray 230/115 kV
19 Substation. In doing so, I explained that these lines are needed in order to route
20 power to SCE&G's customers from two new nuclear units that are under
21 construction at the V.C. Summer Nuclear Station in Jenkinsville, South Carolina
22 ("Unit 2" and "Unit 3" or collectively the "Units"). In that docket, the Commission

1 granted SCE&G a Certificate of Environmental Compatibility and Public
2 Convenience and Necessity for the construction and operation of the VCS1-Killian
3 230 kV Line, the VCS2-Lake Murray 230 kV Line No. 2, and the Segment of VCS2-
4 St. George 230 kV Line No. 1.

5 **Q. PLEASE DESCRIBE THE PURPOSE OF YOUR DIRECT TESTIMONY.**

6 A. SCE&G continually monitors and reviews its transmission construction cost
7 forecast related to the Units. Since the issuance of Order No. 2011-345 dated May
8 16, 2011, issued in Docket No. 2010-376-E, the Company has updated its
9 transmission construction cost forecast to reflect new developments and detailed
10 transmission line design in the project, which were not known during the pendency
11 of Docket No. 2010-376-E. The purpose of my direct testimony in this proceeding
12 is to present information related to the adjustments to the transmission
13 construction cost forecast and to explain the necessity of these updates.

14 **Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE TRANSMISSION**
15 **LINES THAT ARE NECESSARY TO CONNECT UNITS 2 AND 3 TO THE**
16 **GRID.**

17 A. SCE&G has determined that four (4) new 230 kV lines originating at the
18 V.C. Summer Nuclear Station will be required to route the generated capacity of
19 the Units to the Company's electric transmission grid. These lines are identified
20 as follows:

1 1. **The VCS1-Killian 230 kV Line.** This line is required to route
2 power from the V.C. Summer plant site to the northeast Columbia area. This line
3 begins at the existing V.C. Summer Switchyard #1 which is located at the plant
4 site and terminates at the existing Killian 230/115 kV Substation which is located
5 in northeast Columbia near the intersection of Interstate 77 and Farrow Road. The
6 total length of this line is approximately thirty-seven (37) miles and will be routed
7 entirely within SCE&G's existing rights-of-way except for the Blythewood-
8 Killian segment (approximately 6 miles), which will be routed along new rights-
9 of-way.

10 2. **The VCS2-Lake Murray 230 kV Line No. 2.** This line is required
11 to route power to the Lexington and Irmo areas. This line will begin at the V.C.
12 Summer Switchyard #2 which is presently under construction at the plant site. It
13 will run to the existing Lake Murray 230/115 kV Substation which is located near
14 the Saluda Hydro and McMeekin Station sites just below the Lake Murray dam.
15 The total length of this line is approximately twenty-two (22) miles and will be
16 routed entirely within SCE&G's existing rights-of-way.

17 3. **The VCS2-St. George 230 kV Line No. 1.** This line is required to
18 route power to the southern part of SCE&G's electric system, which includes the
19 Greater Charleston area. The VCS2-St. George 230 kV Line No. 1 will originate
20 at the V.C. Summer Switchyard #2 and run to the planned St. George 230 kV
21 Switching Station near St. George, South Carolina. The length of the VCS2-St.
22 George 230 kV Line No. 1 will be approximately ninety-seven (97) miles. A

1 twenty-two (22) mile segment of the VCS2-St. George 230 kV Line No. 1, for
2 which the Commission granted SCE&G a Certificate in Order No. 2011-978, will
3 run alongside the VCS2-Lake Murray 230 kV Line No. 2 between the V.C.
4 Summer Switchyard #2 and the Lake Murray 230/115 kV Substation.

5 4. **The VCS2-St. George 230 kV Line No. 2.** This line is also
6 required to route power to the southern part of SCE&G's electric system including
7 the Greater Charleston area. The VCS2-St. George 230 kV Line No. 2 will
8 originate at the V.C. Summer Switchyard #2 and run to the planned St. George
9 230 kV Switching Station near St. George, South Carolina. The VCS2-St. George
10 230 kV Line No. 2 will extend approximately ninety-four (94) miles in length.

11 In addition to these four (4) new 230 kV lines, SCE&G will also construct
12 three (3) 230 kV bus ties on the V. C. Summer Nuclear Station site to connect the
13 existing V.C. Summer Switchyard #1 to the future V.C. Summer Switchyard #2.

14 A depiction of the VCS1-Killian 230 kV Line, the VCS2-Lake Murray 230
15 kV Line No. 2, the VCS2-St. George 230 kV Line No. 1, the VCS2-St. George
16 230 kV Line No. 2, and the three (3) bus ties is shown on the map attached hereto
17 as Exhibit No. __ (HCY-1). The total combined circuit length of the four new
18 SCE&G lines will be approximately 250 circuit miles which will be built along
19 153 corridor miles of right-of-way.

1 Q. WHAT IS THE CURRENT STATE OF WORK ON THE NEW
2 TRANSMISSION LINES?

3 A. VCS1-Killian 230 kV Line – In early January 2012, in accordance with
4 Order No. 2011-978, SCE&G began construction on the VCS1-Killian 230 kV
5 Line. As of June 30, 2012, approximately forty percent (40%) of the VCS1-
6 Killian 230 kV Line is complete.

7 VCS2-Lake Murray 230 kV Line No. 2 and Segment of the VCS2-St.
8 George 230 kV Line No. 1 – In May 2012, and in accordance with Order No.
9 2011-978, SCE&G began construction on the VCS2-Lake Murray 230 kV Line
10 No. 2. The Segment of the VCS2-St. George 230 kV Line No. 1 which extends
11 from V.C. Summer Switchyard #2 to the Lake Murray 230/115 kV Substation is
12 being constructed concurrently with the VCS2-Lake Murray 230 kV Line No. 2.
13 As of June 30, 2012, line construction is approximately five percent (5%)
14 complete.

15 Remaining Segment of VCS2-St. George 230 kV Line No. 1 and the
16 VCS2-St. George 230 kV Line No. 2 – The Company has not yet commenced
17 construction of these lines. On June 1, 2012, SCE&G filed an application,
18 pursuant to the Utility Facility Siting and Environmental Protection Act, with the
19 Commission seeking the issuance of a Certificate of Environmental Capability and
20 Public Convenience and Necessity for these lines (excluding the Segment of
21 VCS2-St. George 230 kV Line No. 1) and associated facilities. The Commission
22 scheduled a hearing on this matter for August 22, 2012.

1 **Q. WHEN ARE THE NEW TRANSMISSION LINES SCHEDULED TO BE**
2 **COMPLETED?**

3 A. The VCS1-Killian 230 kV Line, VCS2-Lake Murray 230 kV Line No. 2,
4 and Segment of VCS2-St. George 230 kV Line No. 1 is scheduled to be completed
5 by December 31, 2014. Subject to Commission approval in Docket No. 2012-
6 225-E, the remainder of the VCS2-St. George 230 kV Line No. 1 and the VCS2-
7 St. George 230 kV Line No. 2 is scheduled to be completed by May 1, 2017;
8 however, an approximately seven (7) mile segment of the VCS2-St. George 230
9 kV Line No. 2 that will serve as the power source for the new Saluda River
10 230/115 kV Transmission Substation ("SRT Substation"), which I discuss later in
11 my testimony, is scheduled to be completed by May 31, 2015.

12 **Q. PLEASE PROVIDE THE COMMISSION WITH AN OVERVIEW OF THE**
13 **ADJUSTMENTS TO SCE&G'S TRANSMISSION CONSTRUCTION COST**
14 **FORECAST.**

15 A. In Order No. 2009-104(A) and Order No. 2011-345, the Commission
16 approved a transmission construction cost forecast for SCE&G totaling
17 \$321,591,000. In its request in this proceeding, the Company is seeking to adjust
18 its Commission-approved transmission construction cost forecast in the net
19 amount of \$7,921,000. A breakdown and description of the specific adjustments
20 is set forth in the table on the following page of my direct testimony.

21

22

No.	Adjustment Description	Amount
1	Construct SRT Substation	\$1,591,000
2	Transmission Line Construction	\$3,624,000
3	Upgrades to Various Substation Equipment	\$2,712,000
4	Real Property Acquisitions	\$1,383,000
5	Reallocation of Costs between SCE&G and Santee Cooper	(\$1,389,000)
	Total	\$7,921,000

1

2 **Q. WHY HAVE THESE ADJUSTMENTS NOT BEEN PRESENTED TO THE**
3 **COMMISSION BEFORE NOW?**

4 **A.** The adjustments stated above and described in more detail in my testimony
5 have not been presented to the Commission before now because they were not
6 known. SCE&G's prior transmission construction cost forecast was based on
7 estimates that were supported by early, conceptual designs. As the transmission
8 projects have progressed and more comprehensive information has become
9 available, certain additional projects have been identified as necessary for safety,
10 reliability or operational purposes.

11

12

ADJUSTMENT NO. 1
CONSTRUCT SRT SUBSTATION

13 **Q. PLEASE EXPLAIN THE COMPANY'S DECISION TO CONSTRUCT THE**
14 **SRT SUBSTATION.**

15 **A.** The electric load for the Lexington and Irmo areas is currently supported by
16 the Lake Murray 230/115 kV Substation as well as the McMeekin and Saluda
17 Hydro 115 kV generations. The electric load for the downtown Columbia area is
18 supported by the Lyles 230/115 kV Substation, the Denny Terrace 230/115 kV

1 Substation and other sources. SCE&G's original transmission plans and system
2 needs anticipated that the new transmission lines would be constructed along
3 green-field routes. As Mr. Byrne explained in his direct testimony, the Company
4 employed a macro-corridor approach to siting and identifying potential
5 transmission line routes and their environmental effects in its Environmental
6 Report supporting the Company's Combined Operating License Application. That
7 is to say, SCE&G identified the county-by-county corridors through which the
8 transmission lines supporting the Units would run. The specific location of the
9 line routes within the macro-corridors would be identified later in the process after
10 formal siting and detailed engineering studies were completed.

11 The option of constructing the new transmission lines along these identified
12 green-field routes required the Company to install an additional 336 megavolt
13 amperes ("MVA"), 230/115 kV autotransformer at its Lake Murray 230/115 kV
14 Substation and its Denny Terrace 230/115 kV Substation which would distribute
15 the additional output supplied by the new Units to the Lexington, Irmo and
16 Columbia areas. SCE&G anticipated that the cost for the additional
17 autotransformers would total approximately \$13,900,000 in 2007 dollars.

18 In response to scheduling considerations and comments received from
19 several state and federal agencies indicating a strong preference for the use of
20 existing right-of-way corridors for the new transmission lines, SCE&G began to
21 investigate how the Company could use its existing transmission line rights-of-
22 way to the maximum extent practicable for the four (4) new SCE&G 230 kV lines

1 associated with Units 2 and 3. The subsequent decision to build the new 230 kV
2 lines on existing rights-of-way and the location of these rights-of-way allowed for
3 new options to be considered for distributing the power output of Unit 2 to the
4 Lexington, Irmo and Columbia areas. As a result, the Company concluded that it
5 would be more economical, practical and beneficial to system reliability to
6 construct the new SRT Substation rather than to construct additional
7 autotransformers at its Lake Murray 230/115 kV Substation and its Denny Terrace
8 230/115 kV Substation as originally planned.

9 **Q. WAS THE OPTION OF CONSTRUCTING THE SRT SUBSTATION**
10 **FEASIBLE IN 2008?**

11 A. No. As I have testified, the Company's original plans anticipated that the
12 transmission lines would be constructed along green-field routes that did not pass
13 near the location of the future SRT Substation. By following this green-field
14 route, the new transmission lines would not follow a route that would allow for the
15 construction of the SRT Substation. Under the green-field route option, the only
16 feasible option available to the Company for delivering the Units' power to the
17 Lexington, Columbia, and Irmo areas was to add additional autotransformers at
18 the Lake Murray and Denny Terrace Substations.

19 **Q. WHERE WILL THE SRT SUBSTATION BE LOCATED?**

20 A. The SRT Substation will be built on approximately fifty (50) acres of land
21 in Lexington County, South Carolina. The property fronts Davega Road just south
22 of Interstate Highway 20 between the Bush River Road and U.S. Highway 378

1 interchanges. SCE&G anticipates clearing approximately fifteen (15) acres to
2 develop final grade for the substation. The remainder of the property will remain
3 a wooded area and will provide screening of the substation from surrounding
4 areas. Attached to my testimony as Exhibit No. ____ (HCY-2) is a map which
5 depicts in general terms the site and location of the future SRT Substation.

6 **Q. WHEN ANALYZING THE CONSTRUCTION OF A NEW 230/115 KV**
7 **SUBSTATION DID SCE&G CONSIDER ANY OTHER ALTERNATIVES?**

8 A. Yes. The first alternative considered was the original plan to construct an
9 additional 336 MVA autotransformer at both the Lake Murray and Denny Terrace
10 230/115 kV Substations. The existing Lake Murray and Denny Terrace substation
11 sites are not large enough to accommodate the additional autotransformer. As
12 such, this alternative would require the construction of a second 230/115 kV
13 substation near each existing site to accommodate the additional autotransformer
14 at each location. This alternative also would require installing another 336 MVA
15 autotransformer at the Lyles 230/115 kV Substation and upgrading the conductor
16 on three existing 115 kV lines.

17 The second alternative would require adding another autotransformer at the
18 Lyles 230/115 kV Substation and rebuilding the Edenwood-Lake Murray 230 kV
19 Line.

20

21

1 Q. IS CONSTRUCTING THE SRT SUBSTATION PREFERABLE TO
2 CONSTRUCTING ADDITIONAL AUTOTRANSFORMERS?

3 A. Yes. As testified above, at the outset of this project in 2007, SCE&G
4 planned to construct additional autotransformers at the Lake Murray and Denny
5 Terrace Substations; however, in the design phase of these projects it was
6 determined that the Lake Murray and Denny Terrace substations were not large
7 enough to accommodate the additional autotransformers. As a result, SCE&G
8 modified this alternative to include the construction of new substations adjacent to
9 the existing Lake Murray and Denny Terrace Substations in order to accommodate
10 the additional autotransformers. SCE&G also determined that an additional
11 autotransformer would be required at the Lyles Substation. The construction of
12 two new substations along with the addition of another autotransformer at the
13 Lyles Substation adds significant costs to this alternative and also places numerous
14 transformers in a single location which creates reliability and operational
15 concerns. With the decision to locate the new 230 kV lines on existing rights-of-
16 way, the new VCS2-St George 230 kV lines are now passing through the Irmo,
17 Lexington and West Columbia areas where the new transformer capability is
18 needed. This decision allowed additional options for locating the required
19 autotransformer capability, including the site of the proposed SRT Substation.
20 Additional studies considering these new options determined that the SRT
21 Substation option provided all the reliability and operational requirements and was

1 less costly when compared to the updated cost associated with the Lake Murray,
2 Denny Terrace, and Lyles autotransformer alternative.

3 **Q. WHAT DID THE COMPANY CONCLUDE?**

4 A. SCE&G refreshed its estimates and concluded that it would cost
5 approximately \$27,800,000 in 2007 dollars to construct the additional
6 autotransformers. Not only was the construction of the new SRT Substation
7 preferable to constructing additional autotransformers from a reliability
8 perspective, the construction of the new SRT Substation was the least cost
9 alternative available to the Company.

10 **Q. WHAT IS THE ESTIMATED COST TO CONSTRUCT THE SRT**
11 **SUBSTATION AND ASSOCIATED PROJECTS?**

12 A. For Base Load Review Act purposes, the cost to construct the new SRT
13 Substation in 2007 dollars is approximately \$15,500,000. This cost includes the
14 following:

- 15 1. Substation Construction;
- 16 2. Site Acquisition;
- 17 3. Connecting the Saluda Hydro-Williams Street 115 kV Line to
18 the SRT Substation, which creates the Saluda Hydro-SRT 115
19 kV Line and the SRT-Williams Street 115 kV Line;
- 20 4. Connecting the Lake Murray-Lyles 115 kV Line to the SRT
21 Substation, which creates the Lake Murray-SRT 115 kV Line
22 and the SRT-Lyles 115 kV Line;
- 23 5. Upgrade of the SRT-Lyles 115 kV Line; and
24
25

1 6. Addition of a 230 kV terminal at the Lake Murray 230/115kV
2 Substation.
3

4 There are additional costs associated with the construction of the SRT
5 Substation. However, these costs are classified as system improvement costs, and
6 therefore SCE&G is not seeking recovery of these costs under the Base Load
7 Review Act. At the appropriate time, SCE&G will present the costs classified as
8 system improvement costs to the Commission for its review and approval.

9 **Q. WHY IS THE UPGRADE OF THE SRT-LYLES 115 kV LINE NEEDED?**

10 A. The SRT-Lyles 115 kV Line will be upgraded to 1272 ACSR conductor
11 which is a higher capacity conductor. This upgrade is required to distribute the
12 power from V.C. Summer Unit 2 to the Columbia load center without violating
13 any NERC or SCE&G Internal Planning Criteria. Without the upgrade, the
14 existing conductor on this line will overload for certain events/outages on the
15 transmission system. The resulting system condition would not meet the
16 transmission requirements of NERC or SCE&G.

17 **Q. WHAT IS THE PROJECTED IN-SERVICE DATE FOR THE SRT**
18 **SUBSTATION?**

19 A. The projected in-service date for the SRT Substation is May 31, 2015.

20 **Q. PLEASE RECONCILE THE COST OF THE ADDITIONAL**
21 **AUTOTRANSFORMERS WITH THE COST OF THE SRT SUBSTATION.**

22 A. As I testified earlier, the Commission-approved cost to construct additional
23 autotransformers at the Lake Murray and Denny Terrace Substations without

1 constructing the necessary additional substations at those sites to accommodate the
2 autotransformers is approximately \$13,900,000 in 2007 dollars. SCE&G later
3 refreshed its estimates and concluded that it would cost approximately
4 \$27,800,000 in 2007 dollars to construct the additional
5 autotransformers/substations. By constructing the new SRT Substation, the need
6 for the additional autotransformers no longer exists. Therefore, SCE&G plans to
7 apply the \$13,900,000 previously approved for the additional autotransformers to
8 the cost of constructing the new SRT Substation, which is \$15,500,000.
9 Accordingly, SCE&G has increased its transmission cost forecast in the amount of
10 \$1,591,000.

11 **Q. IS THE ADDITION OF THE SRT SUBSTATION REASONABLE AND**
12 **PRUDENT?**

13 **A.** Yes, it is. These costs reflect a prudent and valuable investment that the
14 Company is making in this project.

15 **ADJUSTMENT NO. 2**
16 **TRANSMISSION LINE CONSTRUCTION**
17

18 **Q. PLEASE IDENTIFY THE SCOPE OF WORK IDENTIFIED AS**
19 **TRANSMISSION LINE CONSTRUCTION.**

20 **A.** The updated costs for Transmission Line Construction reflect SCE&G's
21 decision to underground a section of the existing Parr-VCSN Safeguard 115 kV
22 line where that line would have crossed multiple 230 kV transmission lines.
23 Transmission Line Construction also reflects the lowering of the Parr-Midway 115

1 kV Lines. These lines must be lowered to allow the VCS2-Lake Murray 230 kV
2 Line No. 2, the VCS2-St. George 230 kV Line No. 1, the VCS2-St. George 230
3 kV Line No. 2, and other 230 kV lines to meet required minimum National
4 Electric Safety Code crossing clearances.

5 **Q. PLEASE EXPLAIN SCE&G'S DECISION TO UNDERGROUND A**
6 **SEGMENT OF THE EXISTING PARR-VCSN SAFEGUARD 115 KV LINE.**

7 A. The Parr-VCSN Safeguard 115 kV Line currently provides back-up power
8 to the safety-related components of Unit 1 at the V.C. Summer Station site.
9 SCE&G considers this line to be a critical component for the safe operation of
10 Unit 1 because its serves to provide back-up power to Unit 1. Currently, the Parr-
11 VCSN Safeguard 115 kV Line crosses over one (1) 230 kV line and two (2) 115
12 kV lines. By constructing the new switchyard, the new 230 kV transmission lines
13 along existing rights-of-way and reconnecting other existing transmission lines to
14 the new switchyard, SCE&G's design plans would require the Parr-VCSN
15 Safeguard 115 kV Line to cross over five (5) 230 kV transmission lines.

16 SCE&G has evaluated the Parr-VCSN Safeguard 115 kV Line and its
17 relation to the configuration of the five (5) 230 kV transmission lines that it would
18 cross. During this evaluation, the Company identified reliability and safety issues
19 concerning the multiple 230 kV lines which the 115 kV safeguard line would
20 cross. To alleviate these reliability and safety concerns, a short segment of the
21 Parr-VCSN Safeguard 115 kV Line will be rebuilt underground at the site of these
22 multiple crossings.

1 **Q. PLEASE BRIEFLY EXPLAIN THE RELIABILITY AND SAFETY**
2 **CONCERNS IDENTIFIED BY SCE&G.**

3 A. As I testified earlier, the Parr-VCSN Safeguard 115 kV Line would cross
4 above several other planned 230 kV transmission lines at the plant site. If a pole
5 or insulator supporting the Parr-VCSN Safeguard 115 kV Line failed at or near the
6 crossing, then the Parr-VCSN Safeguard 115 kV Line could fall onto the
7 transmission lines that it crosses over causing the transmission lines to fault and to
8 be removed from service by breaker operations. The worst scenario would be if
9 the 115 kV line fell and came to a rest on the 230 kV lines at the crossing without
10 falling off during the fault and circuit breaker sequence of operations. This
11 scenario would result in the failed Parr-VCSN Safeguard 115 kV Line continuing
12 to fault the 230 kV lines until the circuit breakers operated through their reclose
13 cycle. After all reclose attempts, the Parr-VCSN Safeguard 115 kV Line and all
14 the 230 kV lines would lock out of service. The result would be a major event on
15 the system possibly causing loss of service to a large number of customers. For
16 these reasons, it is necessary that a segment of the Parr-VCSN Safeguard 115 kV
17 Line be placed underground.

18 **Q. WHAT IS THE ESTIMATED COST TO UNDERGROUND THE PARR-**
19 **VCSN SAFEGUARD 115 KV LINE?**

20 A. It will cost approximately \$2,920,000 in 2007 dollars to underground this
21 segment of the line.

22

1 Q. PLEASE EXPLAIN SCE&G'S DECISION TO LOWER THE PARR-
2 MIDWAY 115 KV LINES.

3 A. As I testified earlier, the VCS2-Lake Murray 230 kV Line No. 2 and the
4 VCS2-St. George 230 kV Line No. 1 originate at the V.C. Summer Switchyard #2.
5 In addition, one existing and one future Santee Cooper 230 kV line, and three
6 other SCE&G 230 kV lines—two of which ultimately connect to Duke Energy's
7 system—will originate or terminate at V.C. Summer Switchyard #1 or #2. These
8 seven (7) 230 kV lines must cross over the Parr-Midway 115 kV Lines to reach
9 their respective termination points. If the Parr-Midway 115 kV Lines are not
10 lowered, then aspects of these lines would require significant design
11 considerations to meet National Electric Safety Code crossing clearances.
12 Accordingly, lowering the Parr-Midway 115 kV Lines is the most cost effective
13 solution.

14 Q. WHAT IS THE COST TO LOWER THE PARR-MIDWAY 115 KV LINES?

15 A. It cost \$704,000 in 2007 dollars to lower the Parr-Midway 115 kV Lines.

16 Q. IS THE UNDERGROUNDING OF THE PARR-VCSN SAFEGUARD 115
17 KV LINE AND THE LOWERING OF THE PARR-MIDWAY 115 KV
18 LINES REASONABLE AND PRUDENT?

19 A. Yes. For the reasons provided earlier in my testimony, these costs reflect a
20 prudent and valuable investment that the Company is making in this project.

21

22

ADJUSTMENT NO. 3
UPGRADES TO VARIOUS SUBSTATION EQUIPMENT

1
2
3
4 Q. WHAT SCOPES OF WORK ARE INCLUDED WITHIN ADJUSTMENT
5 NO. 3?

6 A. The scopes of work included within Adjustment No. 3 consist of the
7 replacement of a disconnect switch in the V.C. Summer Switchyard #1 and
8 various improvements at three (3) substations.

9 Q. PLEASE EXPLAIN THE ADJUSTMENT CONCERNING THE
10 REPLACEMENT OF A DISCONNECT SWITCH IN THE SWITCHYARD.

11 A. SCE&G must replace a bus side disconnect switch in the V.C. Summer
12 Switchyard #1 along with the existing lightning arresters. Today, the existing
13 disconnect switch does not have the power current rating necessary to function
14 properly when Units 2 and 3 become operational. As a result, SCE&G must
15 upgrade the existing disconnect switch. In addition, the existing lightning
16 arresters must be upgraded. With higher capacity lines being installed to
17 accommodate the power flows of Units 2 and 3, the replacement of the disconnect
18 switch must occur; otherwise, the disconnect switch would be the most limiting
19 component of the transmission line resulting in a de-rating of the line.

20 Q. WHAT IS THE COST FOR THIS SCOPE OF WORK?

21 A. The replacement of the disconnect switch in the V.C. Summer Switchyard
22 #1 is \$614,000.
23

1 Q. PLEASE EXPLAIN THE IMPROVEMENTS REQUIRED AT THE THREE
2 SUBSTATIONS.

3 A. SCE&G must make improvements at three (3) of its existing substations –
4 all of which are necessary to interconnect the new transmission lines with
5 SCE&G's existing system in a safe and reliable manner.

6 At SCE&G's Canadys 230 kV Substation, the Company must upgrade the
7 bus and terminal to St. George. The Canadys-St. George 230 kV transmission line
8 will be rebuilt/upgraded with bundled 1272 ACSR conductor. The existing bus
9 and the terminal for this line at the Canadys Substation does not have the power
10 current rating necessary to function properly when this new equipment is installed.
11 Therefore, SCE&G must upgrade the bus and breaker line terminal power current
12 rating at its Canadys Substation to accommodate the bundled 1272 ACSR
13 conductor.

14 At SCE&G's Summerville 230 kV Substation, the Company must upgrade
15 the terminal to St. George. The Summerville-St. George 230 kV transmission line
16 will be rebuilt/upgraded with bundled 1272 ACSR conductor. The existing
17 terminal for this line at the Summerville Substation does not have the power
18 current rating necessary to function properly when this new equipment is installed.
19 Therefore, SCE&G must upgrade the breaker line terminal power current rating at
20 its Summerville Substation to accommodate the bundled 1272 ACSR conductor.

21 At SCE&G's Saluda Hydro Substation, the Company must upgrade two (2)
22 terminals to Newberry. The Saluda Hydro-Newberry 115 kV transmission lines

1 will be rebuilt/upgraded to 1272 ACSR conductor. The existing terminals for
2 these lines at the Saluda Hydro Substation do not have the power current rating
3 necessary to function properly when this new equipment is installed. Therefore,
4 SCE&G must upgrade two terminals at its Saluda Hydro Substation to
5 accommodate the upgraded lines.

6 **Q. WHAT IS THE ESTIMATED COST FOR THIS SCOPE OF WORK?**

7 **A.** This estimated cost for this scope of work is \$2,098,000.

8 **Q. ARE THE COSTS TO REPLACE THE DISCONNECT SWITCH AND THE**
9 **COSTS FOR THE BUS AND TERMINAL UPGRADES REASONABLE**
10 **AND PRUDENT?**

11 **A.** Yes. These costs reflect a prudent and valuable investment that the
12 Company is making in this project.

13 **ADJUSTMENT NO. 4**
14 **REAL PROPERTY ACQUISITIONS**

15 **Q. PLEASE DESCRIBE THE ADJUSTMENT RELATED TO REAL**
16 **PROPERTY ACQUISITIONS.**

17 **A.** This adjustment consists of the purchase of rights-of-way to construct the
18 Blythewood-Killian Segment of the VCS1-Killian 230 kV Line and the settlement
19 amounts paid to Richland County and the Town of Blythewood in Docket No.
20 2011-325-E.
21

22

1 **Q. PLEASE EXPLAIN THE NEED TO ADJUST THE TRANSMISSION COST**
2 **FORECAST CONCERNING THE BLYTHEWOOD-KILLIAN SEGMENT.**

3 A. As I testified earlier, the Blythewood-Killian Segment of the VCS1-Killian
4 230 kV Line is the only portion of the line which will be constructed along new
5 rights-of-way; therefore, SCE&G must purchase new rights-of-way to construct
6 this segment of the line. In formulating its initial transmission cost forecast, the
7 exact route for the Blythewood-Killian Segment was not known. As a result, the
8 costs associated with this segment of the line were based on estimated routing,
9 length, and right-of-way needs. Since the formation of the initial transmission cost
10 forecast, SCE&G has completed its formal siting process for the Blythewood-
11 Killian Segment and identified the actual route for this portion of the VCS1-
12 Killian 230 kV Line. After identifying the actual route, SCE&G updated its
13 forecast of right-of-way acquisition costs. Based upon the foregoing, SCE&G has
14 increased its transmission cost forecast in the amount of \$369,000 for the
15 necessary rights-of-way for the Blythewood-Killian Segment.

16 **Q. HAS SCE&G SECURED ALL THE RIGHTS-OF-WAY ALONG THE**
17 **BLYTHEWOOD-KILLIAN SEGMENT?**

18 A. The Company has secured access to all property along the Blythewood-
19 Killian Segment; however, SCE&G had to initiate several condemnation actions
20 against certain landowners to secure this access. While SCE&G has secured
21 access to these properties, the purchase price for these rights-of-way has not yet
22 been finalized. Therefore, it is possible that a court may issue an order requiring

1 SCE&G to pay more for the rights-of-way than expected. If this were to occur,
2 then the Company would be required to return to the Commission to further adjust
3 this portion of its transmission cost forecast.

4 **Q. PLEASE EXPLAIN THE SETTLEMENT AMOUNTS PAID TO**
5 **RICHLAND COUNTY AND THE TOWN OF BLYTHEWOOD IN**
6 **DOCKET NO. 2011-325-E AND IN DOING SO, PLEASE EXPLAIN WHY**
7 **THE SETTLEMENT AMOUNTS SHOULD BE INCLUDED IN THE**
8 **TRANSMISSION CONSTRUCTION COST BUDGET.**

9 **A.** In Docket No. 2011-325-E, SCE&G entered into a Settlement Agreement
10 with Richland County and a Settlement Agreement with the Town of Blythewood.
11 Pursuant to the Settlement Agreement with Richland County, SCE&G, among
12 other things, agreed to pay the County \$1,000,000. Pursuant to the Settlement
13 Agreement with the Town of Blythewood, SCE&G, among other things, agreed to
14 pay the Town \$450,000. Both Settlement Agreements resolved all issues and
15 contentions raised by the County and the Town; and in consideration of the
16 Settlement Agreements, both the County and the Town agreed to support the
17 issuance of a Certificate of Environmental Compatibility and Public Convenience
18 and Necessity as requested by SCE&G in its Application in Docket No. 2011-325-
19 E.

20 Prior to entering into the Settlement Agreement with Richland County, the
21 County was actively opposing the route selected by SCE&G for the Blythewood-
22 Killian Segment of the VCS1-Killian 230 Line. If Richland County had been

1 successful in its efforts opposing the route for the Blythewood-Killian Segment
2 (approximately six miles), then SCE&G would have been required to re-route and
3 construct this segment of the VCS1-Killian 230 kV Line along existing rights-of-
4 way and pursue an alternate route for the Blythewood-Killian 115 kV Line which
5 would have cost SCE&G an additional \$6,300,000. By entering into a Settlement
6 Agreement with Richland County, SCE&G avoided this potential additional
7 expense for its customers.

8 Prior to entering into the Settlement Agreement with the Town of
9 Blythewood, the Town was actively opposing a section of the proposed
10 Winnsboro-Blythewood Segment of the VCS1-Killian 230 kV Line. The section
11 of the line in dispute crossed the intersection of Blythewood Road and Northbound
12 Interstate 77 at Exit 27. This area is commonly referred to as the "Gateway to
13 Blythewood." In its opposition, the Town argued that SCE&G should either
14 underground this section of the line or re-route the line along a different route and
15 away from the Gateway to Blythewood. If the Town had been successful in its
16 efforts requiring SCE&G to underground this section of the line, SCE&G
17 estimated that it would have cost approximately \$26,000,000 to comply with the
18 Town's request. On the other hand, if SCE&G had been required to re-route this
19 section of the line away from the Gateway to Blythewood, then the issuance of the
20 Combined Operating License (COL) for the new nuclear units could have been
21 placed in jeopardy because SCE&G would be routing the line in a manner
22 inconsistent with the transmission line route description set forth in the

1 Environmental Report. The Environmental Impact Statement for the new nuclear
2 units is based upon the Environmental Report and supplemental information and
3 the COL is based on the Environmental Impact Statement. In addition to the
4 endangerment to the issuance of the Combined Operating License, the re-routing
5 of this section of the line in the manner recommended by the Town would have
6 cost at least \$2,000,000. By entering into a Settlement Agreement with the Town
7 of Blythewood, SCE&G avoided this risk to the COL and these potential
8 additional expenses for its customers.

9 **Q. WITH REGARD TO THE SETTLEMENT AMOUNTS PAID TO**
10 **RICHLAND COUNTY AND THE TOWN OF BLYTHEWOOD, HOW**
11 **MUCH IS SCE&G ADJUSTING ITS TRANSMISSION COST FORECAST?**

12 **A.** The Company is not including the full settlement amounts within its
13 transmission cost forecast which is consistent with the commitment SCE&G made
14 to the Commission in Docket No. 2008-196-E and approved in Commission Order
15 No. 2009-104(A). In that docket, I testified that SCE&G intended to route the
16 VCS1-Killian 230 kV Transmission Line in such a manner to better serve the
17 growth along the Interstate 77 corridor or north Columbia. I further testified that
18 because SCE&G was routing the line in this manner that only 74.2% of the costs
19 associated with the VCS1-Killian 230 kV Transmission Line would be included in
20 the transmission cost forecast under the Base Load Review Act. Accordingly,
21 SCE&G is adjusting its transmission cost forecast in the amount of \$1,014,000 in
22 2007 dollars for the settlement amounts paid to Richland County and the Town of

1 Blythewood. In keeping with the Company's commitment to the Commission and
2 in compliance with Commission Order No. 2009-104(A), this amount represents
3 74.2% of the settlement amounts.

4 **Q. IS THE COST FOR THE REAL PROPERTY ACQUISITIONS**
5 **REASONABLE AND PRUDENT?**

6 A. Yes, it is. These costs reflect a prudent and valuable investment that the
7 Company is making in this project.

8 **ADJUSTMENT NO. 5**
9 **REALLOCATION OF COSTS BETWEEN SCE&G**
10 **AND SANTEE COOPER**
11

12 **Q. PLEASE EXPLAIN THE ADJUSTMENT CONCERNING THE**
13 **REALLOCATION OF COSTS AMONG SCE&G AND SANTEE COOPER.**

14 A. As the Commission is aware, SCE&G jointly owns the Units with Santee
15 Cooper. SCE&G's ownership share is 55%, and Santee Cooper's ownership share
16 is 45%. In addition to jointly owning the Units, SCE&G and Santee Cooper also
17 jointly own the V.C. Summer Switchyard #1, V.C. Summer Switchyard #2, and
18 several other transmission assets at or near the project site. As a result, SCE&G
19 and Santee Cooper share in the costs associated with these assets. Recently,
20 SCE&G and Santee Cooper re-evaluated their ownership of these assets and
21 agreed to a new methodology for allocating costs among the two companies.
22 Instead of assigning individual terminals, switches and other items of property
23 between SCE&G and Santee Cooper, we decided to allocate the full costs of each

1 switchyard based upon a percentage reflecting each company's use of the
2 equipment. As a result of this new methodology, SCE&G's share of transmission
3 costs decreased.

4 **Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT ON THE**
5 **TRANSMISSION CONSTRUCTION COST BUDGET?**

6 **A.** The impact of this adjustment results in a \$1,389,000 decrease to the
7 transmission construction cost budget.

8 **CONCLUSION**

9 **Q. ARE THE ADJUSTMENTS REQUESTED IN THIS PROCEEDING**
10 **REASONABLE AND PRUDENT?**

11 **A.** Yes. All the adjustments discussed in my direct testimony are reasonable
12 and prudent costs necessary to construct the transmission lines associated with the
13 Units.

14 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

15 **A.** Yes.

1 **MR. BURGESS:** Mr. Chairman, Mr. Young is
2 available for cross-examination by the parties, as
3 well as any questions by the Commission.

4 **CHAIRMAN WRIGHT:** Thank you, Mr. Burgess. Mr.
5 Guild.

6 **MR. GUILD:** Mr. Chairman, I have no questions
7 for Mr. Young. Thank you.

8 **CHAIRMAN WRIGHT:** Mr. Elliott.

9 **MR. ELLIOTT:** Please. Indulge me, a second.

10 **CROSS EXAMINATION**

11 **BY MR. ELLIOTT:**

12 **Q** Mr. Young, I got in a hurry yesterday with Mr. Byrne,
13 and I need -- would impose on you to help me understand
14 several things --

15 **A** Certainly.

16 **Q** -- that pertain to the actual siting of the lines for
17 the purposes of this project. Now, we came in in 2008.
18 I recall you were here and testified in that proceeding?

19 **A** I did.

20 **Q** In the original Base Load Act, and -- Base Load Act
21 proceeding. And, at that time, as I understand your
22 testimony and Mr. Byrne's testimony, you had decided --
23 the company had decided -- to use this macro-corridor
24 concept to lay out or site its transmission lines. Is
25 that correct?

1 A I don't think it was our decision. What we did is, we
2 filed our COLA with the impact from transmission like
3 Southern had filed theirs, which was a macro-corridor
4 concept, identifying "Here's where we think the lines
5 will go."

6 Q Okay. So you copy-catted Southern, initially, correct?

7 A [Indicating.]

8 Q All right. And as I understand it, Westinghouse -- if
9 we can just call it "Westinghouse" -- was responsible
10 for getting the Combined Operating License, correct?
11 That was their responsibility? Do you understand that
12 to be the case?

13 A My understanding is that we were responsible for the
14 COL, that Westinghouse would be responsible for -- were
15 responsible to make sure their design was approved by
16 the NRC.

17 Q All right, I'll work with that. It's not really my
18 question. My question is: In addition, SCE&G was
19 responsible for obtaining the wetlands permits --

20 A That's correct.

21 Q -- necessary for the transmission lines.

22 A That's correct.

23 Q That's where I'm getting. All right. And, again, this
24 is where I'm not clear, but as I understood Mr. Byrne's
25 testimony yesterday, you had at least several options,

1 or SCE&G -- when I say "you," I mean SCE&G -- had at
2 least several options available to it for siting its
3 lines. Is that correct?

4 A That's true.

5 Q All right. And one option is this macro-corridor option
6 or design; is that correct?

7 A That is not a complete option. That was a way to inform
8 the NRC of the potential environmental impact from the
9 transmission lines. It did not site the lines. It only
10 said, "We believe we can site lines in this area."

11 Q Good. You're helping me. So, for the purposes of
12 informing the Corps of the wetlands issues, one option
13 was to use the macro-corridor design. Have I captured
14 it correctly now?

15 A That was our initial approach, yes.

16 Q All right.

17 A We filed the macro corridor with the Corps.

18 Q All right. And Mr. Byrne was clear about this, and I'm
19 clear, but in essence, you look at a series of county
20 maps and you propose a corridor for your transmission
21 lines, and you're able to ascertain at some level what
22 the wetlands issues are going to be within that
23 corridor. Is that a --

24 A That's correct.

25 Q -- fair, generalized statement?

1 A In the macro corridor, we were charged with identifying
2 all the wetlands that occurred there. We were charged
3 with ensuring that we could build a transmission line
4 and avoid any wetlands impact in that corridor.

5 Q All right. Now, another option for ascertaining your
6 wetlands issues as a part of your siting process would
7 be to use the existing easements that you have -- that
8 you had in hand in 2008, correct?

9 A That is not really a separate alternative. The macro
10 corridor simply was a way to inform the transmission
11 impact related to the COL -- the Corps permit and the
12 COL. Our siting process, which -- it's a comprehensive
13 process that finds the least-resistance and the least-
14 impact route for a transmission line. So when we are
15 siting a line from V.C. Summer, let's say to St. George,
16 we identify an area we think the line will go through,
17 and if there are existing routes in that macro corridor,
18 they are potential candidates for how we'd want to
19 expand the system. But, we don't normally just jump to
20 that as our answer. We will go through public
21 workshops, where we invite all the landowners --
22 according to tax maps -- who own land in that study
23 area; we will invite them to public workshops where we
24 sit down. We have stations in these workshops where we
25 identify the need for the project. My team normally

1 commands that: why we need to build the line. There's
2 a team that looks at the environmental impact of where
3 wetlands are in the area, where archaeological finds
4 might be in the area, where historical places might be
5 in the area, endangered species. All of these factor
6 into the ultimate decision of where will the line go.
7 Other stations in that workshop include what the line
8 will potentially look like, health effects, and then a
9 station that identifies how we -- our approach in
10 acquiring right-of-way and easements. All of that is
11 available to inform the public, and to also allow the
12 public an opportunity to tell us and give us input as to
13 something that we are not aware of.

14 So we have these workshops, and typically we have
15 two. We'll have a public workshop where we simply say,
16 "Here's the area where we need to build a line in," and
17 we do all the things I just mentioned. Then, we go back
18 and study all the data and all the input and all the
19 survey information that we gather from the customers --
20 and I failed to mention that. We also survey them to
21 find out what's important to them. Is it important that
22 the line be not visible from homes? Is it important for
23 the line to be not visible from roadways? Is it
24 important to avoid schools? Those types of questions
25 are on that survey. So we actually use those surveys to

1 determine the rating of these factors. And so the
2 public actually, in their opinion, helps us choose the
3 appropriate site for the line that's going through their
4 area.

5 Q Okay.

6 A Let me just wrap that up.

7 Q Please. No, no.

8 A Once we get all this information, we schedule a second
9 public hearing, where we go back and say, "We have
10 evaluated all the data. We have 14 routes that we think
11 all are feasible routes that we can build this line
12 through this area." And we tell them the details of
13 those 14 routes, and again we ask, "What's your input?"
14 At the end of the day, when we finish that second
15 meeting, we go back and do the analysis on all the new
16 data, and we ultimately make the decision, including
17 factoring in what the cost of the different alternatives
18 would be, to ultimately decide "This is the best route
19 with the least impact on land use and customers."

20 Q Thank you. That was very helpful. Now, so you had
21 these public meetings. You held these public meetings.
22 And you had some -- you got a lot of input into your
23 placement of these lines, did you not?

24 A We had two public meetings on the corridor between
25 Blythewood and Killian. That is the six-mile section

1 that is new right-of-way. So we were identifying a new
2 route -- what's commonly referred to as a green-field
3 route -- through that area. So, yes, we had two public
4 sitings -- two public workshops, and ran that process.

5 We had one workshop on the Winnsboro-to-Blythewood
6 section of the V.C. Summer/Killian line. Shortly after
7 that workshop -- and if I'm remembering right, this was
8 the third quarter of 2010 -- we made the decision to go
9 to existing routes. And so, existing routes were in
10 that corridor I just talked about, and so, at the end of
11 the study process, we may have determined that the
12 existing route is the best option.

13 And what happened to us in the third quarter of
14 2010 is, we had to make a call there about whether we
15 were going to continue to pursue green-field -- which we
16 don't know the schedule for that. We would still be
17 trying to pursue -- my opinion -- we would still be
18 trying to pursue route acquisition, if we were going
19 green-field. So we had to make a decision, an important
20 decision there, about "We're going to have to go on
21 existing right-of-way." That is what the EPA required
22 of our permit. They didn't -- the EPA is the one that
23 axed the macro-corridor concept. They said, "We don't
24 want to know general impact. We want to know specific
25 impact. What is the route, and what is the route with

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1 that impact?" And so we had to make that decision at
2 that point, so we cut to the existing-route solution,
3 alternative, right then. And we've been working that
4 ever since.

5 Q All right. Good, sir. Now, third quarter of '10 would
6 be what months of 2010?

7 A July.

8 Q July, August?

9 A I don't remember specifically. June, July, August,
10 somewhere in that timeframe.

11 Q Okay. And so, EPA requires you to use existing right-
12 of-ways -- rights-of-way -- in July of '10, and you had
13 your wetlands permit in December of '11. Correct?

14 A Correct.

15 Q So that would be roughly 18 months?

16 A That's correct.

17 Q Okay. And now, the EPA certainly was within its rights
18 and its authority under the law to require you to use --
19 to satisfy them by using existing rights-of-way,
20 correct?

21 A I don't know what law gave them that right. I do know
22 that they changed between what they required Southern to
23 submit, because they approved -- they endorsed the
24 Corps' permit for Southern Company with the macro
25 concept, and they did not endorse it with ours.

1 Q But we can agree, can we not, that the transmission
2 circumstances in Georgia were different from the
3 transmission circumstances in South Carolina?

4 A Well, this is EPA, so it's national.

5 Q You and I might be able to agree about the EPA, outside
6 the hearing, but with respect to the transmission lines
7 in Georgia, they travel over different land and routes
8 than your transmission lines travel here in South
9 Carolina?

10 A Sure, yes.

11 Q Okay. And so you knew that there was a risk in 2008
12 that EPA might treat you differently from the way they
13 treated Southern, didn't you?

14 A I did not personally know that.

15 Q You did not perceive that risk.

16 A In 2008, we assumed the macro corridor, which was an
17 accepted concept, an accepted way to do this, would
18 continue to work.

19 Q And using your existing easements is also an accepted
20 way to show your wetlands issues and to show you're
21 prepared to deal with them, correct?

22 A Yes.

23 Q All right. And so, we were here in this proceeding in
24 December of 2008, and the order came out sometime in
25 February or March of 2009. Do you recall that, in the

1 original Base Load proceeding?

2 A It sounds right.

3 Q And you understood that you had to get your wetlands
4 permits -- well, your COL permit, under your benchmark,
5 by July of 2011, correct?

6 A No.

7 Q You don't understand that?

8 A I'm not sure I'm following your question.

9 Q Do you know when the Combined Operating -- when your
10 milestone for your Combined Operating License approval
11 was, under your original Base Load Review order? You
12 may not know.

13 A I can't recall that, off the top of my head. But I am
14 aware of the milestones, yes.

15 Q All right. So you just don't recall or do not know that
16 the Combined Operating License milestone was July of
17 2011, in your original Base Load order.

18 A That's when we expected to get --

19 Q All right.

20 A -- the COL, yes.

21 Q And you would have had to have had your wetlands permit
22 in hand by the same date, would you not?

23 A I think wetlands, for the plant, maybe so. Wetlands for
24 the transmission, we needed those by the time we were
25 constructing those lines, transmission lines.

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1 Q But we can agree that the lapse of time between the
2 February or March 2008_[sic] order and July of 2011 was
3 about 28 months, can we not? We can agree to that; it's
4 just a fact?

5 A It sounds right.

6 Q And had you -- had SCE&G pursued their wetlands permit
7 using their rights-of-way, their existing rights-of-way,
8 they would have -- based on our experience in this
9 matter -- they would have had their wetlands issues
10 resolved before the July of 2011, correct?

11 A Again, we made our decision to go on existing right-of-
12 way in the third quarter of 2010.

13 Q And if you'd made that decision in March of 2008_[sic], the
14 wetlands issues would've been resolved before your
15 Combined Operating License milestone occurred, correct?

16 A If we had made that decision earlier, but that's not how
17 we go about siting transmission lines. We use the
18 process that I discussed, which includes new
19 transmission corridors and includes the option to use
20 existing transmission corridors.

21 Q Well, I do want to talk to you just for a moment about
22 the process you used. And let me be clear, because I'm
23 not, and just please clarify it. You are here today
24 supporting an increase of exactly how much, for
25 additional transmission costs in this docket?

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1 A \$7.9 million.

2 Q So the total is \$7.9 million. And do you recall
3 testifying, at least in your prefiled testimony -- I
4 didn't hear it in your summary -- that your original
5 transmission construction cost forecast was based on
6 estimates that were supported by early conceptual
7 designs?

8 A That's correct.

9 Q And that term struck me as sounding familiar. Do you
10 recall -- were you here when Mr. Lavigne and I were
11 talking?

12 A I was.

13 Q And do you recall I asked him about his data, and that
14 -- and do you recall him testifying that he wrote a
15 response to his interrogatory that his data was -- that
16 the data submitted in his area of expertise was based on
17 general estimates and preliminary design information?
18 Do you recall him testifying he wrote that?

19 A That's correct. I do.

20 Q And so, would you agree that both characterizations --
21 one as to your transmission design in 2008 and the other
22 as to your personnel estimates, if you will, in 2008,
23 sound very similar, based on the testimony of today?

24 A Okay.

25 Q And can't we agreed that, if you had based your

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1 transmission siting on something more than early
2 conceptual designs, you may have come to the conclusion
3 in February of 2009, March 2009, that using your
4 existing rights-of-way would be a more quick way of
5 getting your wetlands permits?

6 A I don't think I would say we could jump to that
7 decision. Building transmission lines on existing
8 right-of-way creates its own issues, such as, using
9 existing right-of-way, that means there's a transmission
10 line already there, so that transmission line is needed
11 to deliver power from generators to customers. And so
12 building another line on that right-of-way or changing
13 what that -- what the construction on that right-of-way,
14 what it looks like, means that we've got to take
15 facilities out of service in order to build the new
16 facilities. And so we've got to find times -- we've got
17 to find operational conditions that will allow us to
18 take the existing line down, relocate the existing lines
19 -- whatever we're going to do on that existing right-of-
20 way to make room for the new line to come through. So
21 there are significant operational constraints that we
22 must deal with.

23 So in terms of operating the transmission system,
24 the existing right-of-way is the complicated way,
25 because we've got to still maintain service to our

1 customers while we're doing our construction project. A
2 green-field, new right-of-way, we don't have to deal
3 with it. We don't have to take something out of
4 service. Because we're on a new right-of-way, there's
5 nothing there that requires us to take it out of
6 service. So that is actually the easier way to build
7 the lines.

8 What complicated this was our need to do what the
9 EPA asked us to do in the permit, and that is, identify
10 your specific route. And you are right, that made the
11 decision quicker. But what it caused us to do was jump
12 over all the options of doing something on a green-field
13 route. It made us go to -- it dictated our answer; our
14 answer was going to be existing right-of-way. And I
15 can't sit here and tell you that existing right-of-way
16 is the cheapest alternative, because we're taking lines
17 out of service and building them back, to make room for
18 these.

19 So it is the quickest way, because I do believe we
20 would still be pursuing right-of-way. We wouldn't know
21 our routes yet. We wouldn't have been able to tell EPA
22 "Here's the exact route, here's the exact impact." We
23 would not have, in my opinion, the COL today, if we were
24 still pursuing green-field routes.

25 Q And part of that is because that when you design a

1 brand-new route through somebody's backyard, they're
2 going to object, isn't it?

3 A Correct.

4 Q And if you design a route that goes through, that
5 bisects a person's cornfield -- and I've never seen a
6 situation where it didn't go right down the middle --
7 the farmer objects, correct?

8 A Yes.

9 Q And so if you were basing your transmission construction
10 cost forecast on something beyond just a concept or an
11 idea, then you would anticipate the public objection or
12 furor over building new lines, and you would determine
13 that the existing rights-of-way were the safer way to
14 go, wouldn't you?

15 A Not necessarily, because, as you called it, landowner
16 furor is not the only component that decides where the
17 transmission lines should go. It is all the factors,
18 including that. And when we have to build a new line,
19 Mr. Elliott, you know, I understand. You know, I'm
20 landowner. I understand the impact that occurs there.
21 But our charge is not to have zero impact; our charge is
22 to minimize the impact. And so, our process, I believe,
23 does a very good job of determining the minimum impact
24 of getting the line between Point A and Point B.

25 Q But --

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1 A And one other thing.

2 Q Please.

3 A The conceptual design question you asked, we cannot do
4 the exact final design of the transmission line until we
5 know the right-of-way. It can't be done at a macro
6 corridor. It must be the right-of-way. And so, that's
7 when we decide whether we need to put in an 80-foot pole
8 or a 95-foot pole. It depends on the contour of the
9 land that we are crossing. And so all of those things
10 are factored into the design of the line.

11 So, in '08, we do not know the exact route. We did
12 not have that information. And going through the
13 process, I mentioned in our workshops -- you know, we
14 narrow it down to maybe 14 different routes -- and that
15 number varies; that's only an example -- 14 different
16 routes. It wouldn't be right for us to tell our
17 Engineering group to go and engineer 14 different
18 routes, when only one of the 14 is going to ever be
19 built. That is a lot of work to put on an Engineering
20 group, to say, "We want to know the details of all the
21 alternatives." So decisions are absolutely made at the
22 conceptual estimate level. That's how we must do
23 business.

24 Q But SCE&G was not surprised at the public furor over
25 these new lines, was it sir?

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1 **A** Oh, no. No. We hear that, and we understand that. I
2 have compassion for it. When the route finally goes in
3 and it impacts some landowner, I understand their
4 burden. But again, we are charged with minimizing that
5 burden. We can't -- we can't continue to build
6 infrastructure in this State, from the transmission
7 perspective, that will prepare our State for future
8 growth, future good jobs, future high-paying jobs
9 hopefully, and move us forward, without expanding the
10 infrastructure. And so, yes, we do impact landowners.
11 The landowners where the ultimate route is selected
12 absolutely have impact. But we believe, both in general
13 and overall, we have minimized that impact.

14 **Q** And the fact is inescapable, is it not, that, had you
15 used the acceptable option of using your existing
16 rights-of-way, you would have gotten your wetlands
17 permits timely, isn't it?

18 **A** I believe that is a true statement, but we would have
19 bypassed all the other options that we talked about of
20 trying to do it better and making sure we're doing the
21 right thing.

22 **Q** I understand. Thank you, very much, Mr. Young. I
23 appreciate it.

24 **A** Thank you.

25 **CHAIRMAN WRIGHT:** Thank you. Ms. Greenlaw.

REDIRECT EXAMINATION**BY MR. BURGESS:**

Q Mr. Young, was it reasonable and prudent to use the macro-corridor approach at the outset of the project?

A Would it have been more prudent?

Q Was it reasonable and prudent to use the macro-corridor approach?

A Absolutely. The thought in 2008 was to identify that macro-corridor, because that's what was needed for the Corps and what the -- well, that's what was needed for the Corps. What we anticipated at that time was that we would follow up with these public workshops, and that we felt we had time -- in 2008 -- to conduct these public workshops and identify the best corridor, including the option of a new route and including the option of existing routes.

So it was prudent at that point. What changed -- again, what caused us to change our direction with that was the EPA requirement that we identify the exact corridor, which we didn't know the answer to, at that point. So in the third quarter of 2010, we made that decision.

Q Mr. Young, whether or not you use the macro-corridor approach or if you had used the existing right-of-way approach, you don't know what date the Corps would have

1 issued the permit, do you?

2 A That's correct, do not.

3 MR. BURGESS: No further questions.

4 CHAIRMAN WRIGHT: Thank you. Mr. Elliott, any
5 redirect_[sic] based on --

6 MR. ELLIOTT: No, thank you.

7 CHAIRMAN WRIGHT: Okay. Anybody else?

8 [No response]

9 All right. If there are no other questions --
10 you want him to be excused?

11 MR. BURGESS: Yes, please. Thank you.

12 WITNESS: Thank you, very much.

13 CHAIRMAN WRIGHT: You're excused.

14 [WHEREUPON, the witness was excused.]

15 MR. BURGESS: We would call Carlette Walker to
16 the stand.

17 [Witness sworn]

18 THEREUPON came,

19 C A R L E T T E L . W A L K E R ,

20 called as a witness on behalf of the Petitioner, South
21 Carolina Electric & Gas Company, who, having been first duly
22 sworn, was examined and testified as follows:

23 DIRECT EXAMINATION

24 BY MR. GISSENDANNER:

25 Q Please state your name for the record.

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1 A It's Carlette Walker.

2 Q And by whom are you employed, and in what capacity?

3 A SCANA Corporation, and I'm the vice president of Nuclear
4 Finance Administration.

5 Q And, Ms. Walker, have you prepared or caused to be
6 prepared under your supervision direct testimony of 23
7 pages that was previously filed with the Commission in
8 this docket?

9 A I did.

10 Q And do you have any changes or additions to your
11 prefiled testimony?

12 A I do not.

13 Q And if I were to ask you the same questions here today,
14 would your answers be the same?

15 A They would.

16 MR. GISSENDANNER: Mr. Chairman, at this time,
17 I move that the prefiled direct testimony of Ms.
18 Walker be read into the record as if given orally
19 from the stand.

20 CHAIRMAN WRIGHT: Ms. Walker's prefiled direct
21 testimony will be read into the record as if given
22 orally from the stand.

23 [See pgs 702-724]

24 BY MR. GISSENDANNER:

25 Q And, Ms. Walker, have you prepared or caused to be

1 prepared under your direct supervision three exhibits
2 labeled as Exhibit CLW-1, CLW-2, and CLW-3. that were
3 previously filed with the Commission as attachments to
4 your prefiled direct testimony in this docket?

5 **A** I did.

6 **Q** And do you have any changes or revisions to your
7 exhibits?

8 **A** No.

9 **MR. GISSENDANNER:** Mr. Chairman, I would also
10 move into the record, as the next hearing composite
11 exhibit, the exhibits attached to Ms. Walker's
12 prefiled direct testimony and labeled as Exhibit
13 CLW-1, CLW-2, and CLW-3. And, in addition, I would
14 note for the record that there is a public version
15 of CLW-1 and CLW-3, as well as a confidential
16 version of CLW-1 and CLW-3, and we would ask that
17 the confidential version of these exhibits be
18 maintained under seal, in accordance with the
19 Commission's order in this docket.

20 **CHAIRMAN WRIGHT:** Ms. Walker's three exhibits,
21 CLW-1, -2, and -3, the public versions will be made
22 part of the evidence of the case, and the
23 confidential versions of Exhibit -1 and -3 will be
24 kept under seal, and it will be a composite
25 exhibit; it will be No. 6, will be all of this.

1 and the Commissioners. So I just rise to make sure
2 that that is in this record for the purposes of --
3 for our purposes here and for purposes after this
4 proceeding.

5 CHAIRMAN WRIGHT: Are you in agreement?

6 MR. GISSENDANNER: Yes, that's fine.

7 CHAIRMAN WRIGHT: We'll make sure it's
8 included.

9 [See pgs 726-829]

10 MR. ELLIOTT: Don't have to do it now, but --
11 I have what I need for today, but I'd like it to be
12 a part of the record. Thank you, very much.

13 CHAIRMAN WRIGHT: [Indicating.]

14 MR. GISSENDANNER: Thank you.

15 BY MR. GISSENDANNER:

16 Q Ms. Walker, have you prepared a summary of your direct
17 testimony?

18 A I have.

19 Q Would you please deliver that at this time?

20 A Good afternoon, Mr. Chairman and members of the
21 Commission. My testimony presents the accounting,
22 budgeting, and forecasting support for the updates to
23 the cost schedules that are proposed in this proceeding.

24 As part of my testimony, I sponsor Exhibit CLW-1,
25 which is an updated schedule of capital costs for the

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1 construction of the units. The cash flow forecast
2 contained in Exhibit CLW-1 reflects the most recent
3 capital cost forecasts from Westinghouse/Shaw. If
4 approved by the Commission, this schedule would become
5 the approved capital cost schedule for the units under
6 the Base Load Review Act.

7 I'm also sponsoring Exhibit CLW-2, which shows the
8 relative changes to the capital cost schedule, comparing
9 the updated schedule of the capital cost to the schedule
10 approved in the initial BLRA order. As explained in my
11 direct testimony, these two exhibits are equivalent to
12 the principal financial exhibits to the Petition in this
13 docket.

14 As other witnesses have testified, the company is
15 proposing four categories of adjustments to the current
16 capital cost schedules: The first of these are the
17 costs associated with the rescheduling of the project
18 due to the COL delay, shield building redesign,
19 structural module design, and the Unit 2 rock
20 conditions. These are the costs associated with Change
21 Order No. 16 to the Engineering, Procurement, and
22 Construction Agreement -- or the EPC contract -- for the
23 units.

24 Second, the company has continued to refine and
25 update Summer's cost projections since they were made --

1 since they were made in the 2006-2008 time period,
2 especially in light of new regulatory requirements.
3 SCE&G has continued to improve its forecast of staffing,
4 facilities, and information technology needed to support
5 the units. The company has adjusted its cost forecast
6 to reflect these refinements.

7 Third, SCE&G has identified certain updates that
8 are required to the transmission system, to ensure the
9 reliable and efficient transmission of the power from
10 the units.

11 Fourth, the cost schedules have been updated to
12 reflect three other change orders to the EPC contract
13 which relate to cybersecurity, healthcare, and
14 wastewater piping.

15 Based on these updates and change orders, the
16 company has itemized and identified approximately \$283
17 million in additional capital costs for the project
18 which are reflected in the attached schedules. In my
19 testimony, I provide an accounting reconciliation of the
20 current cost projections to the projections approved by
21 this Commission in Order No 2011-345. This allows the
22 Commission to identify and verify what the drivers of
23 these changes are.

24 The effect of the adjustments to cost forecasts is
25 to increase the approved capital cost schedule for the

1 units in 2007 dollars from \$4.535 billion, as approved
2 in the original BLRA order, to \$4.553 billion, a net
3 change of \$18 million. However, this adjustment is
4 offset by changes in the escalation rates which,
5 collectively, have reduced the cost of the units from
6 \$6.313 billion, as originally projected, to \$5.762
7 billion, a net change of \$551 million.

8 In my testimony, I provide a summary table for
9 owners' costs, representing the updated costs for the 27
10 New Nuclear Deployment, or NND, cost centers, and for
11 the other 51 non-NND cost centers that we have
12 anticipated will charge to the project, organized by
13 functional area. Included in these budget tables are
14 the updates in staffing, hiring, and training plans
15 discussed by Mr. Lavigne. This budget table also shows
16 owners' costs broken down by detailed resource code, for
17 each of these 78 NND and non-NND cost centers that
18 underlie the summary NND budget documents. For each of
19 the entries in the budget, there is a separate set of
20 schedules that break these costs down month by month,
21 from the project inception to date, and year by year for
22 the period 2013 through 2018. Each cost center manager
23 has developed a budget that is based on his or her
24 experience and professional assessment of the future
25 needs of the project. They are supported by staffing

1 and training plans, current corporate salary structures,
2 outside service budgets, and other cost centers'
3 specific budget documents as available. These detailed
4 cost-center budgets roll up and support the overall
5 budget that I present. ORS has had full access to these
6 budget documents for audit and review, as have any
7 parties that have been willing to sign the standard
8 confidentiality agreement regarding them.

9 In addition, I testify specifically to the changes
10 in the owners' costs that are not related to the hiring,
11 staffing, and training changes that Mr. Lavigne
12 discusses. Updates in the categories I discuss reflect
13 a broad range of changes which arise out of an annual
14 cost center by cost center update, and a review of the
15 cost forecasts for all cost centers expected to bill
16 more than \$5,000 to the project.

17 I have identified principal drivers for these
18 updates to be changes in the information technology plan
19 for the units, as well as changes in the facility plan
20 for housing of personnel and training activities, and
21 equipment necessary to support them.

22 These cost variances are the result of several
23 factors: The lessons learned from Fukushima, a better
24 understanding of the capabilities of our existing IT
25 infrastructure and changes to our IT delivery approach,

1 better information about facilities design and operating
2 costs, reviews of facility plans based on a revised
3 staffing projection, and increased site security
4 requirements. I am familiar with these plans and
5 forecasts, and how they were compiled and reviewed. It
6 is my testimony that the changes they represent are
7 reasonable and prudent costs of the project.

8 On an ongoing basis, the NND team, including the
9 NND financial team that I lead, has carefully reviewed
10 the budget forecast provided for these costs, to ensure
11 that these costs that they include were reasonable and
12 appropriate. The NND team also engaged in a series of
13 challenge meetings with cost-center groups to test the
14 reasonableness of their budget forecasts.

15 Since the inception of this project, the NND team
16 has been diligent in reviewing costs charged to the
17 project from non-NND areas. The current budgets for the
18 project reflect our experience in revising and analyzing
19 charges to this project, and our understanding of the
20 future needs of the project as it has evolved.

21 The new cost schedules, as reflected, also reflect
22 the timing of the expenses and payments associated with
23 the updated construction schedule for the project.

24 In conclusion, the company requests that the
25 Commission approve the updated cost schedule in my

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1 Exhibit CLW-1 as the approved schedule of capital costs
2 for the units, subject to adjustment for escalation and
3 net of AFUDC, as provided for in Order 2009-104(A). The
4 adjustments presented in the Petition and included in
5 the updated capital cost schedule are reasonable,
6 prudent, and necessary changes, and are not the result
7 of any imprudency on the part of the company.

8 MR. GISSENDANNER: Thank you, Ms. Walker.
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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY OF CARLETTE L.
25 WALKER FOLLOWS AT PGS 702-724]

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DIRECT TESTIMONY OF

CARLETTE L. WALKER

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2012-203-E

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Carlette L. Walker. My business address is 1162 State Highway 213, Jenkinsville, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by SCANA Services, Inc. as Vice President for Nuclear Finance Administration. I am testifying on behalf of South Carolina Electric & Gas Company ("SCE&G" or the "Company").

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I am a 1981 graduate, cum laude, of the University of South Carolina with a Bachelor of Science Degree in Accounting. Following graduation, I worked for two years in public accounting and became licensed as a Certified Public Accountant in the State of South Carolina. In 1983, I joined SCE&G's Internal Audit Department. After four years in Internal Audit, I accepted an accounting supervisory position with South Carolina Pipeline Corporation ("SCPC"). In 1994, I was promoted to Manager of SCPC's accounting department, and in 1997,

1 I was promoted to the position of Controller for that company. In 1998, I accepted
2 the position of SCE&G's Assistant Controller - Electric Generation, and in 1999 I
3 was promoted to Assistant Controller - SCE&G. Effective in 2002, my
4 responsibilities as Assistant Controller were increased to include all SCANA
5 regulated subsidiaries. In 2006, I was promoted to Corporate Compliance and
6 Ethics and Audit Officer. In 2009, I assumed my current position as Vice
7 President for Nuclear Finance Administration.

8 I am currently a member of the American Institute of Certified Public
9 Accountants and the South Carolina Association of Certified Public Accountants.

10 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION IN THE**
11 **PAST?**

12 A. Yes. I have testified before the Public Service Commission of South
13 Carolina (the "Commission") in several past proceedings.

14 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

15 A. The purpose of my testimony is to present the accounting, budgeting and
16 forecasting information related to the updates in cost schedules proposed in this
17 proceeding. As part of my testimony, I sponsor Exhibit No. __ (CLW-1), which is
18 an updated schedule of capital costs for construction of V. C. Summer Nuclear
19 Station Units 2 and 3 (the "Units"). This document is identical to Exhibit 2 to the
20 Petition. If approved by the Commission, this schedule would become the
21 approved capital costs schedule for the Units under the Base Load Review Act,
22 taking the place of Exhibit F as approved in Order No. 2009-104(A), and Exhibit 2

1 as approved in Order No. 2011-345. I am also sponsoring Exhibit No. ____ (CLW-
2 2), which shows the relative changes to the capital costs schedule comparing the
3 updated schedule of capital costs to the schedule approved in Order No. 2009-
4 104(A), as amended by Order Nos. 2010-12 and 2011-345. These two exhibits are
5 also exhibits to the petition in this docket (the "Petition").

6 **Q. WHAT REQUEST IS THE COMPANY MAKING IN THIS DOCKET**
7 **WITH REGARD TO THE CAPITAL COSTS SCHEDULE?**

8 A. SCE&G is requesting that the Commission approve Exhibit No. ____
9 (CLW-1), as the approved capital costs schedule for the construction of the Units
10 going forward.

11 **Q. WHAT IS THE AUTHORITY FOR THIS REQUEST?**

12 A. As the South Carolina Supreme Court recognized in its opinion in *South*
13 *Carolina Energy Users Comm. v. South Carolina Pub. Serv. Comm'n*, 388 S.C.
14 486, 697 S.E.2d 587 (2010) ("*South Carolina Energy Users Comm.*"), changes to
15 the approved capital costs schedule are authorized under S.C. Code Ann. § 58-33-
16 270(E). Under that statute, such modifications to approved schedules of capital
17 costs are appropriate so long as they are not the result of imprudence by the utility.

18 **Q. PLEASE EXPLAIN THE CAPITAL COSTS SCHEDULE ADJUSTMENTS**
19 **THAT ARE PRESENTED IN THE PETITION.**

20 A. In the Petition, the Company is proposing the following adjustments to the
21 schedules that were approved in Order No. 2009-104(A) and updated in Order No.
22 2011-345.

- 1 1. Change Order No. 16
- 2 2. Updates to Owners cost
- 3 3. Updates to Transmission cost
- 4 4. Three other change orders

5 **Q. WHAT IS THE EFFECT OF THESE PROPOSED ADJUSTMENTS?**

6 A. These changes increase the approved capital costs schedule for the Units in
7 2007 dollars from \$4.3 billion as approved in Order No. 2011-345 to \$4.6 billion.¹
8 These changes are off-set by changes in escalation rates, which collectively have
9 reduced the cost of the Units from \$6.3 billion, as originally projected in the
10 financial schedules that were approved in Order No. 2009-104(A), to \$5.8 billion.

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¹ Unless otherwise specified, all cost figures in this testimony are stated in 2007 dollars net of Allowance for Funds Used During Construction and reflect SCE&G's share of the cost of the Units.

Chart A

RECONCILIATION OF CURRENT COST PROJECTIONS	
TO ORDER NO. 2011-345	
(\$000)	
Revised Forecast (Exhibit No. __ (CLW-1)	\$ 5,761,910
Forecast Order No. 2011-345	\$ 5,786,943
Change	\$ (25,033)
Reconciliation:	
Change Order No. 16 (Shield Building, COL Delay, Modules, Rock Condition, etc.)	\$ 137,500
Owners Cost	\$ 131,625
Transmission Cost	\$ 7,921
Other Change Orders (Cyber Security, Health Care, Wastewater Piping)	\$ 5,905
Total	\$ 282,951
Change in Project Escalation	\$ (290,226)
Change in AFUDC	\$ (17,758)
Net	\$ (25,033)

I would note that the projections presented here reflect current forecasts of escalation impacts which we will update quarterly as required by Order No. 2009-104(A). The current projections do not include any unidentified or un-itemized owner's contingency funds such as those that were contained in the schedules approved in Order No. 2009-104(A).

1 Q. PLEASE PROVIDE A BREAKDOWN OF THE CHANGES IN
2 FORECASTED COST.

3 A. Exhibit No. __ (CLW-3) shows the changes in forecasted costs broken
4 down according to the nine cost categories recognized in the Commission's BLRA
5 orders. This exhibit also shows the changes in costs broken down into eight
6 individual items. These eight items generally fall into four separate categories: (1)
7 Change Order No. 16, which comprises the costs associated with the rescheduling
8 of the project due to COL delay, the shield building redesign, the structural
9 modules redesign and the Unit 2 rock conditions; (2) earlier change orders to the
10 EPC Contract relating to cyber security, health care and wastewater piping; (3) a
11 reforecast of Owners cost in light of all the above changes as well as new
12 regulatory requirements and continued improvements to the staffing plan, the
13 facilities plan, and the information technologies ("IT") plan for the project; and (4)
14 updates to the forecast of Transmission costs. The details of each of these items
15 will be discussed later.

16 **CHANGE ORDER NO. 16**

17 Q. PLEASE ITEMIZE THE FIRST SET OF THESE ITEMS RELATED TO
18 CHANGE ORDER NO. 16.

19 A. The items related to Change Order No. 16 are detailed in Mr. Byrne's
20 testimony. They represent a cost adjustment of \$137.5 million for the project.
21 Exhibit No. __ (CLW-3) shows how the costs of Change Order No. 16 are
22 allocated among the EPC Contract cost categories.

OWNERS COST UPDATES

1
2 **Q. PLEASE EXPLAIN THE NEXT SET OF ITEMS THAT ARE SHOWN ON**
3 **EXHIBIT NO. __ (CLW-3) RELATED TO OWNERS COST.**

4 **A.** The next category of items, Item 10 on Exhibit No. __ (CLW-3), shows the
5 changes in Owners cost forecasts as a result of the reviews of Owners cost that
6 SCE&G has undertaken since 2011. SCE&G has conducted these reviews in light
7 of its continued assessment of the training and personnel requirements for
8 operating the Units, the personnel required to oversee the safety, quality and
9 timeliness of the construction project, the impact on Owners cost from changes in
10 the schedule for completing the Units, reviews of the facilities plan and IT plan for
11 the project in light of current staffing and needs, and annual budget reviews for
12 other costs of the projects. The Exhibit shows that the total amount of Owners
13 cost updates is \$131.6 million.

14 Mr. Lavigne testifies regarding the current staffing plans for operating and
15 maintaining the Units and for the construction project. He testifies to the
16 reasonableness and prudence of these plans and the resulting adjustments to the
17 cost forecasts for the project. I am familiar with the process that he and his team
18 have used for making these updates and the decisions that they have made as a
19 result. I support his conclusion that these updates to the staffing plans reflect
20 prudent and necessary costs of the project.

21 My testimony explains the basis for the other changes in Owners cost
22 projections that are not included in the changes in staffing costs. Those costs

1 reflect a broad range of changes much of which are associated with updates to the
2 IT plan for the Units and the Facilities plan. I am very familiar with these plans
3 and forecasts and how they were compiled and reviewed. It is my testimony that
4 the changes they represent are reasonable and prudent costs of the project.

5 **Q. AS A MATTER OF BACKGROUND, WHAT TYPES OF EXPENSES ARE**
6 **INCLUDED IN OWNERS COST?**

7 A. Owners cost includes costs SCE&G will incur that are related to overseeing
8 the construction project; recruiting, hiring and training staff for the Units;
9 preparing written operating procedures for all aspects of Unit operations,
10 maintenance, safety and security; accepting, testing and maintaining the systems
11 and components of the Units as they are completed and turned over to SCE&G
12 pending completion of each Unit as a whole; obtaining licenses and permits for the
13 project; start-up testing of the Units as they are completed; providing the materials
14 and supplies needed for maintenance of plant systems up to the date of
15 commercial operations. Owners cost also includes a number of construction-
16 related items such as workers' compensation insurance for all contractors and
17 subcontractors, payment of miscellaneous taxes including sales taxes, and certain
18 preconstruction costs.

19 **Q. PLEASE EXPLAIN HOW THE INITIAL FORECAST OF THE COST OF**
20 **THESE ACTIVITIES WAS PREPARED.**

21 A. As discussed in detail in my testimony in Docket No. 2010-376-E, which I
22 ask to be incorporated in the docket of this proceeding by reference, SCE&G

1 created the Owners cost estimates contained in the original 2008 BLRA
2 application while it was evaluating nuclear generation options and negotiating the
3 terms of the EPC Contract. Those estimates were updated in Order No. 2011-345
4 which was issued in Docket No. 2010-376-E. The Owners cost forecasts approved
5 in that docket were based on a detailed staffing plan, the project budget and a cost-
6 center by cost-center review of the cost of the project that had been compiled
7 during the period 2008-2010.

8 The update requested in Docket No. 2010-376-E was specifically required
9 in response to the order of the South Carolina Supreme Court in *South Carolina*
10 *Energy Users Comm.* In that order, the Court ruled that amounts that were not
11 allocated to specific items of cost could not be included in the Commission-
12 approved cost schedules for the Units. SCE&G filed its petition in Docket No.
13 2010-376-E as soon after the order was issued as the cost schedules could be
14 prepared to do so.

15 Since 2011, SCE&G has continued to review, refine and update these
16 owners cost projections based on operating experience with the project, and
17 ongoing analysis of the personnel and facilities needed to safely and efficiently
18 construct and operate the Units and EPC contract change orders. The current
19 projections also reflect the effect of changes in substantial completion dates for the
20 Units and other changes under the EPC contract, as discussed in Mr. Byrne's
21 testimony.

22

1 **Q. WHAT HAS GONE INTO THIS BUDGETING PROCESS?**

2 A. Mr. Lavigne testifies to the process by which the staffing budgets have
3 been updated since 2011. As mentioned above, I have been involved in reviewing
4 the results of this process and support his conclusions regarding the
5 reasonableness and prudence of these revisions. I am sponsoring the revisions to
6 the other aspects of Owners cost which are set forth on the updated budget as
7 shown in Chart B in my testimony. These changes are based on the annual, cost-
8 center by cost-center review of the budget for the project which is described in my
9 testimony in Docket No. 2010-376-E as well as specific revisions to the facilities
10 plan and the newly formulated IT plan for the Units (the "IT Roadmap").

11 **Q. IN PREPARING THE CURRENT OWNERS COST BUDGET, HOW DID**
12 **YOU OBTAIN BUDGET INFORMATION FROM AREAS OTHER THAN**
13 **NEW NUCLEAR DEVELOPMENT?**

14 A. As indicated in prior testimony, we require all cost centers outside of New
15 Nuclear Development ("NND") to assign time and costs directly to the project
16 based on time sheets and invoices for actual work performed. These cost centers
17 include such groups as SCANA Audit Services, Legal, Treasury, Environmental,
18 Risk Management and Insurance, Facilities Management, and multiple groups
19 within current Nuclear Operations such as Unit 1 Health Physics that may assist
20 on an as-needed basis in creating staffing plans and writing operating procedures
21 for parts of Unit 2 & 3 operations.

1 All cost centers that anticipate providing direct support to the project must
2 provide detailed budgets for their activities through 2018 and update the budgets
3 annually. These budgets are typically based on a review of the past amount of
4 assistance provided by the outside group to NND adjusted to reflect any anomalies
5 and to take into account an estimate of how needs for assistance are likely to
6 evolve in the future. My group then carefully reviews these budgets against past
7 experience and our understanding of the future needs of the project. We seek
8 adjustments to them where we disagree with the assumptions or results. Bear in
9 mind, these are budgets and we review what is charged to ensure that nothing is
10 billed to the project except the cost of necessary assistance actually provided.
11 However, we are also vigilant to ensure that these non-NND cost center cost
12 forecasts are reasonable and necessary in all respects.

13 We are equally vigilant as to actual costs billed to the project. The NND
14 teams review these charges each month to ensure that they are accurate, necessary
15 and appropriate. Our joint-owner, Santee Cooper, has an equal interest in making
16 sure that all charges are appropriate and reviews these charges independently on a
17 monthly basis.

18 As to the budgets being presented here, I have reviewed them in detail and
19 am very familiar with them through my role in their internal review and approval
20 and the administration of the project month to month. It is my conclusion that
21 they reflect reasonable, necessary and prudent costs of the project.

1 Q. IS A COPY OF THE CURRENT OWNERS COSTS BUDGET
2 AVAILABLE?

3 A. A summary table of the current Owners cost budget changes is found on
4 Chart B. Consistent with Mr. Marsh's testimony, I would emphasize that this
5 budget will be updated on an on-going basis as the project proceeds.

6 Chart B

Summary of Owners Cost Adjustments (S000)	
Budget Category	Total Variance
All Other	\$ 31,170
Direct SCANA Services	\$ 2,452
NND IT	\$ 28,702
VC Summer Unit 1	\$ 15
NND-Operational Readiness	\$ 81,650
NND Operations	\$ 13,227
Operational Readiness	\$ 51,089
Operational Readiness-Engineering	\$ 17,333
NND-Oversight	\$ 12,268
NND Business & Finance	\$ (526)
NND Construction	\$ 9,640
NND Engineering	\$ (2,434)
NND Finance Admin	\$ (575)
NND Licensing, Permits, & Inspections	\$ (7,574)
NND Management Administration	\$ 4,087
NND Non-Split	\$ 5,934
NND OD&P	\$ 1,604
NND QA	\$ 2,111
NND-Training	\$ 6,535
NND Training	\$ 6,535
Grand Total	\$ 131,624

1 **Q. WHAT DOES CHART B SHOW?**

2 A. Chart B is a budget summary table representing the increased costs for the
3 27 NND cost centers and for the other 51 non-NND cost centers that we anticipate
4 will charge costs to the project organized by functional area. The cost variances
5 reflected in this chart include the variances related to the staffing updates that Mr.
6 Lavigne discusses in his testimony. They also include the results of changes in
7 our approach to delivering IT services both to the NND project, and to the Units
8 after they go into service. These variances also include the revisions we have
9 made to the facilities plans for the Units based on current staffing plans, additional
10 reviews of facilities requirements, reviews of site security requirements, and
11 lessons learned from the Fukushima event and forthcoming regulations related to
12 it. In the case of IT requirements, these costs are set forth in a single summary
13 NND IT cost center that was created to capture these costs. The additional
14 facilities costs are included in the variance for NND Construction. In other cases,
15 the variances reflect costs that benefit various areas of the project and are
16 distributed among various summary budgetary items as they apply to them.

17 **Q. WHAT IS THE BACK-UP MATERIAL FOR THIS BUDGET?**

18 A. In the backup material for Chart B, the costs are broken down by detail
19 resource codes for each of the 78 NND and non-NND cost centers that underlie
20 the summary NND budget documents. For each of the entries in that budget, there
21 is a separate set of schedules that breaks these summarized costs down month-by-
22 month from project inception to date and year-by-year for the period of 2013 to

1 2018. Each cost center manager has developed a budget based on his or her
2 professional assessment of the future needs of the project and experience. These
3 budgets are supported by staffing and training plans, current corporate salary
4 structures, outside services budgets, and other cost center specific budget
5 documents as available. These detailed cost center budgets roll up and support the
6 overall budget set forth here.

7 **Q. WHO CAN REVIEW THIS BACK-UP INFORMATION SUPPORTING**
8 **THE CURRENT BUDGET?**

9 A. We are making the above-mentioned detailed cost center budgets and
10 supporting documentation information available at the site to ORS. Because of
11 the commercially sensitive nature of much of this information, and because in
12 some cases this information contains data about individual employees' salaries, we
13 are asking parties to sign confidentiality agreements if they wish to inspect this
14 data at the construction site.

15 **Q. PLEASE EXPLAIN THE COST DRIVERS RELATED TO "NND IT."**

16 A. Following an intensive review and analysis by subject matter experts, we
17 have determined that it is reasonable, prudent and necessary to increase our budget
18 for IT resources for the project. We are requesting an upward adjustment of \$28.7
19 million to the NND IT cost category. The adjustment reflects increases to costs
20 associated with IT infrastructure, which includes licenses, hardware, software and
21 implementation costs.

1 Q. PLEASE ELABORATE.

2 A. The IT budget for the project that was presented in Docket No. 2010-376-E
3 had been compiled by each of the NND teams for its area. In most cases, the
4 assumption underlying that budget was that it would be possible to use existing
5 Unit 1 programs and infrastructure as the basis for meeting Unit 2 and 3 IT needs.
6 As such, these budgets assumed that the IT costs for the new Units would benefit
7 from the ability to meet their needs using existing IT infrastructure at Unit 1.

8 In 2011, we asked SCANA's IT department ("SCANA IT") to take
9 ownership of this aspect of the project and create the formal IT Roadmap for
10 implementing the plan for serving the new Units. SCANA IT determined that
11 much of the existing IT infrastructure at Unit 1 was not scalable to support the two
12 new Units. This review also resulted in identifying some components within the
13 existing Unit 1 IT infrastructure such as health physics software that were
14 becoming increasingly difficult to maintain because of outdated operating systems.
15 This review also recognized issues surrounding the number of software licenses
16 that were available, the use and application of software maintenance agreements
17 and the overall need to upgrade the current Unit 1 IT infrastructure. As a result, it
18 was determined that much of the Unit 1 IT infrastructure would need to be
19 upgraded to operate under current IT standards. Of course, Unit 1 will share an
20 appropriate allocation of the cost of the new IT infrastructure.

21

1 Q. WHY IS IT INFRASTRUCTURE FOR A NUCLEAR UNIT SO
2 IMPORTANT?

3 A. The IT infrastructure for a nuclear unit is the means by which the operating
4 staff for the unit tracks maintenance history, scheduled and preventive
5 maintenance, parts and inventory on hand, where parts have been used in the plant,
6 maintenance requests, work schedules, fatigue management and a great deal of
7 information that is critical to meeting NRC safety and quality assurance and
8 quality control ("QA/QC") documentation requirements. Typically, every
9 significant piece of equipment in a plant is individually documented in these
10 systems along with all information about its manufacture, repair and service
11 history.

12 Q. ARE THE CHANGES REGARDING IT COSTS REASONABLE AND
13 PRUDENT?

14 A. I have reviewed these IT costs and the budgets and the plans on which they
15 are based. They are reasonable, necessary and prudent costs of the project.

16 Q. PLEASE EXPLAIN THE ITEM "VC SUMMER UNIT 1."

17 A. The item "VC Summer Unit 1" presents costs that are being incurred by
18 Unit 1 employees in direct support of the project. These costs principally reflect
19 the labor costs associated with time spent on the project by Unit 1 employees who
20 have specific expertise that is valuable to the project.

21

22

1 **Q. PLEASE EXPLAIN THE ITEM "NND NON-SPLIT."**

2 A. Most of the costs of the project are divided between SCE&G and Santee
3 Cooper on a 55%-45% allocation. However, as we have discussed in prior cases,
4 SCE&G incurs certain costs that are necessary for its role in the project that do not
5 benefit Santee Cooper directly. These are principally costs for supporting
6 SCE&G's regulatory, finance/treasury or corporate governance/disclosure
7 requirements which are not shared by Santee Cooper as a state governmental
8 institution. The NND Non-Split category captures the incremental cost not
9 billable to Santee Cooper. I have reviewed the forecast of incremental costs
10 and can testify that they are reasonable and necessary costs of the project.

11 **Q. PLEASE EXPLAIN HOW THE CURRENT FACILITIES PLAN FOR THE**
12 **UNITS HAS AFFECTED OWNERS COST FORECASTS FOR THE UNITS.**

13 A. In 2011-2012, SCE&G conducted a review of the facility needs for the
14 project which identified additional facilities costs of \$7.8 million. These costs
15 include the costs of facilities needed to house and support the project staff during
16 construction and the facilities needed to house and support the staff of the Units
17 while they are in operation. Also included in these costs are the costs of operating
18 and maintaining the necessary facilities before commercial operations of the Units
19 begins.

20

21

1 Q. PLEASE EXPLAIN WHERE THESE COSTS ARE REFLECTED IN
2 CHART B.

3 A. The NND Construction budget category shown on Chart B includes these
4 increased facilities costs as well as the additional costs of certain direct
5 construction oversight activities. The variances in facilities costs discussed here
6 are the principal drivers of the increase in the forecasted cost of the NND
7 Construction budget category, but as discussed by Mr. Lavigne, applicable
8 adjustments to staffing costs are also included in the variances shown in this
9 budget category.

10 Q. WHAT IS THE LARGEST COMPONENT OF THESE INCREASED
11 FACILITIES COSTS?

12 A. The largest single component of these costs is building maintenance cost,
13 which is the cost of maintaining and operating the facilities required by the project
14 during the period before the Units go into commercial service. The building
15 maintenance cost variance represents \$1.9 million of the total variance due to the
16 facilities plan.

17 Q. WHAT IS DRIVING THESE INCREASED BUILDING MAINTENANCE
18 COSTS?

19 A. SCE&G has reviewed the building operations and maintenance costs for the
20 project in light of the additional staff requirements and the acceleration of staff
21 hiring that Mr. Lavigne discusses. When hiring is accelerated, building
22 maintenance cost increases because the project is required to house more people

1 for longer periods of time. SCE&G has also reviewed its building maintenance
2 cost forecast in light of other additions to the facilities plan, such as those
3 discussed below, and actual maintenance costs data based on recent operating
4 experience. All of these factors have contributed to the increase in building
5 maintenance cost forecast for the project as discussed in the previous question.

6 **Q. ARE THERE OTHER FACTORS DRIVING THESE INCREASED**
7 **FACILITIES COSTS?**

8 A. Yes. To respond to the accelerated hiring schedule discussed by Mr.
9 Lavigne, and the delay in Westinghouse/Shaw turning over space that they will
10 use during construction, SCE&G will have to add a number of modular buildings
11 and other temporary office space to its facilities plan. It will use those modular
12 buildings and other structures to house NND teams in areas like Operational
13 Readiness, Construction Oversight, QA/QC and Training, and to provide housing
14 for NRC inspectors, and IT teams. The additional cost of this temporary office
15 space over the life of the project will be approximately \$1 million.

16 SCE&G has also forecasted an additional \$1.3 million and \$1.4 million for
17 outfitting and furnishing the service building and maintenance facilities,
18 respectively. These structures are being built by Shaw under the terms of the EPC
19 contract. These structures are now in a design finalized state which allowed us to
20 accurately plan for space and furnishing costs. SCE&G is reconfiguring the new
21 Nuclear Operations Building ("NOB") to accommodate the additional staff that

1 has been identified as being required to operate the Units safely and efficiently.
2 This reconfiguring will add approximately \$.7 million to the facilities budget.

3 **Q. DO OPERATIONAL CHANGES IN RESPONSE TO FUKUSHIMA**
4 **CONTRIBUTE TO THESE INCREASED FACILITIES COSTS?**

5 A. As a result of the lessons learned from Fukushima, and the new standards
6 being set for staffing emergency response functions as a result, SCE&G will
7 maintain a fully staffed fire brigade on site at all times capable of fighting fires at
8 all three Units simultaneously with dedicated emergency response personnel. To
9 house the staff and equipment to meet these requirements SCE&G will build a
10 site-wide Emergency Services Building, the cost of which will be shared with Unit
11 1. The new Units' share of this cost is approximately \$1million.

12 **Q. ARE OTHER ITEMS INCLUDED IN THESE INCREASED FACILITIES**
13 **COSTS?**

14 A. There are two other items included in these adjustments to facilities cost
15 forecasts. First, site security planning has identified the need to modify the facility
16 to assure limited access to the site at the main access control point for the Units at
17 an approximate cost of \$ 0.5 million. A similar amount will be spent to furnish
18 and outfit the plant entry building.

19 These costs, when netted against reduced cost identified in other areas
20 (specifically, -\$0.5 million for security training classrooms), result in the
21 adjustment to facilities cost forecast of \$7.8 million which represents the majority

1 of the adjustment in the NND Construction item in the summary budget variance
2 table.

3 **Q. PLEASE EXPLAIN HOW THE NEED FOR SPARE PARTS TO OPERATE**
4 **THE UNITS AFFECTS THE BUDGET.**

5 A. At present, no change is reflected in the budget for the Spare Parts cost
6 category. In the near future, Westinghouse/Shaw will be required, per the terms of
7 the EPC contract, to provide SCE&G with a list of critical and required spare parts
8 which SCE&G should have access to in order to ensure reliable operation of the
9 Units. The spare parts requirements will be evaluated based on the likelihood of
10 failure of particular components and equipment and the lead-times involved in
11 obtaining or fabricating replacement parts if they are not maintained in spare parts
12 inventories. Based on the list prepared by Westinghouse/Shaw, SCE&G will
13 decide which spare parts to store on site and in what quantities. SCE&G will
14 make these evaluations in consultation with other prospective owners of AP1000
15 units and will seek to expand the pool of spare parts available and reduce the costs
16 of maintaining them by sharing access to certain spare parts among the group.

17 **Q. WHEN WILL THAT PROCESS TAKE PLACE?**

18 A. The evaluation of the need for spare parts and options for stocking those
19 that are required will take place prior to the startup of Unit 2. Once the spare parts
20 list is developed, and provided per the terms of the EPC Contract, the NND team
21 will begin evaluating the listing and ultimately valuing the inventory based on

1 costs in the market. Once that is done, the budgets will be updated to reflect any
2 adjustments if necessary.

3 **TRANSMISSION COST UPDATES**

4 **Q. PLEASE EXPLAIN THE NEXT ITEM THAT IS SHOWN ON EXHIBIT**
5 **No. __ (CLW-3) RELATED TO TRANSMISSION COSTS.**

6 **A.** Item 9 reflects changes to the forecasts of Transmission cost. Mr. Young
7 testifies to the reasonableness and prudence of these. I am familiar with these
8 changes from an accounting and financial standpoint and support his conclusion
9 that they are prudent and reasonable costs of the project.

10 **OTHER CHANGE ORDERS**

11 **Q. PLEASE EXPLAIN THE NEXT SET OF ITEMS THAT ARE SHOWN ON**
12 **EXHIBIT NO. __ (CLW-3) RELATED TO THE OTHER CHANGE**
13 **ORDERS.**

14 **A.** Items 1-4 reflect the costs of Change Orders Nos. 12, 14 and 15 to the EPC
15 Contract, which are related to Shaw health care costs, cyber security, and
16 wastewater piping, respectively.

17 Mr. Byrne testifies to the reasonableness and prudence of the costs
18 reflected in these change orders. I am familiar with these change orders and
19 support his conclusion that they are prudent and reasonable costs of the project.
20
21

1 Q. WHAT IS THE TOTAL NET ADJUSTMENT TO THE EPC CONTRACT
2 COST?

3 A. Items 1-4 and 6 on Exhibit No. __ (CLW-3) reflect the EPC cost changes
4 that the Company is requesting that the Commission approve. They represent
5 approximately \$143 million of the total request.

6 **CONCLUSION**

7 Q. WHAT ARE YOU REQUESTING THIS COMMISSION TO DO?

8 A. The Company is requesting that the Commission approve, pursuant to S.C.
9 Code Ann. § 58-33-270(E), the updated capital costs schedule in Exhibit No. ____
10 (CLW-1) as the approved schedule of capital costs for the Units, subject to
11 adjustment for escalation and net of AFUDC as provided for in Order No. 2009-
12 104(A).

13 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

14 A. Yes, it does.

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22 [PURSUANT TO PREVIOUS INSTRUCTION, THE
23 TESTIMONY OF CARLETTE L. WALKER INCLUDED
24 IN THE APRIL 4, 2011, HEARING IN DOCKET
25 NO. 2010-376-E, FOLLOWS AT PGS 726-829]

VOLUME 3 OF 3
10/3/12

PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1
2 MR. ZEIGLER: Mr. Chairman, SCE&G would call
3 Ms. Carlette Walker to the stand.

4 [Witness sworn]

5 THEREUPON came,

6 CARLETTE L. WALKER,
7 called as a witness on behalf of the Applicant, who, having
8 been first duly sworn, was examined and testified as follows:

9 DIRECT EXAMINATION

10 BY MR. ZEIGLER:

11 Q Please state your name for the record.

12 A Carlette Walker.

13 Q By whom are you employed and in what capacity?

14 A I'm employed by SCANA Services, and I'm the vice
15 president of Nuclear Finance Administration.

16 Q Ms. Walker, have you prepared or caused to be prepared
17 under your supervision and control certain testimony of
18 44 pages that's been prefiled in the record of this
19 proceeding?

20 A I did.

21 Q Are there any changes or corrections to that testimony?

22 A I have two corrections to make. One is to the direct
23 testimony, and that would be page three, line six. The
24 reference to Order No. 2010- should read Order No.
25 2009-.

- 1 Q Correct. And Ms. Walker, is there a correction that you
2 have noted that needs to be made in the application?
- 3 A Yes, there is a correction in the original application
4 from the company. Page six, paragraph 18, the very last
5 or next to the last line, it reads, "Currently, as a
6 result, SCE&G has reclassified approximately \$114.6
7 million." That should read \$144.6 million in owners'
8 costs.
- 9 Q Thank you, ma'am. And as to your prepared testimony, if
10 I were to ask you the questions contained therein today,
11 would your answers from the stand be the same?
- 12 A Yes, they would.
- 13 Q All right. And are there any exhibits to your
14 testimony?
- 15 A There are.
- 16 Q Specifically, there are Exhibits CLW-1 through -4 [sic],
17 if I'm correct?
- 18 A That's correct.
- 19 Q Ms. Walker, are there confidential and public versions
20 of those exhibits?
- 21 A There are.
- 22 Q That would be Exhibits -1 and -3 that have confidential
23 and public versions; is that correct?
- 24 A That's right.
- 25 MR. ZEIGLER: Mr. Chairman, we would move Ms.

1 Walker's prefiled testimony, with the exhibits,
2 into the record at this time, understanding that
3 there is a confidential version of Exhibit -1 and
4 Exhibit -3, which we would ask to be held under
5 seal in the record.

6 CHAIRMAN HOWARD: Ms. Walker's prefiled
7 testimony will be read into the record as if given
8 orally from the stand, and Ms. Walker's Exhibit
9 CLW-1 through -4, and -1 and -3 also have a
10 confidential and public version, and that will be
11 Hearing Exhibit No. 5.

12 MR. ZEIGLER: Thank you, Mr. Chairman.

13 BY MR. ZEIGLER:

14 Q Ms. Walker, did you also prepare certain supplemental
15 direct testimony?

16 CHAIRMAN HOWARD: Mr. Ziegler.

17 MR. ZEIGLER: Yes, sir.

18 CHAIRMAN HOWARD: Apparently we have an
19 Exhibit -5.

20 MR. ZEIGLER: Oh, I'm sorry, I must have
21 skipped that exhibit. Yes, we would also ask
22 Exhibit -5 be included.

23 CHAIRMAN HOWARD: That will be the composite
24 exhibit, part of it.

25 MR. ZEIGLER: Thank you, sir.

1 [WHEREUPON, Hearing Exhibit No. 5,
2 including Public and Confidential
3 Portions, was marked and received in
4 evidence.]
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24 [PREFILED DIRECT TESTIMONY {W/CORRECTION} OF
25 CARLETTE L. WALKER FOLLOWS AT PGS 218-261]

1 DIRECT TESTIMONY OF

2 CARLETTE L. WALKER

3 ON BEHALF OF

4 SOUTH CAROLINA ELECTRIC & GAS COMPANY

5 DOCKET NO. 2010-376-E

6
7 Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

8 A. My name is Carlette L. Walker. My business address is 1162 State
9 Highway 213, Jenkinsville, South Carolina.

10 Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

11 A. I am employed by SCANA Services, Inc. as Vice President for
12 Nuclear Finance Administration. I am testifying on behalf of South
13 Carolina Electric & Gas Company ("SCE&G" or the "Company").

14 Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND
15 BUSINESS EXPERIENCE.

16 A. I am a 1981 graduate, cum laude, of the University of South
17 Carolina with a Bachelor of Science Degree in Accounting. Following
18 graduation, I worked for two years in public accounting and became
19 licensed as a Certified Public Accountant in the State of South Carolina. In
20 1983, I joined SCE&G's Internal Audit Department. After four years in
21 Internal Audit, I accepted an accounting supervisory position with South
22 Carolina Pipeline Corporation ("SCPC"). In 1994, I was promoted to

1 Manager of SCPC's accounting department and in 1997, I was promoted to
2 the position of Controller for that company. In 1998, I accepted the
3 position of SCE&G's Assistant Controller - Electric Generation and, in
4 1999, I was promoted to Assistant Controller - SCE&G. Effective in 2002,
5 my responsibilities as Assistant Controller were increased to include all
6 SCANA regulated subsidiaries. In 2006, I was promoted to Corporate
7 Compliance and Ethics and Audit Officer. In 2009, I assumed my current
8 position as Vice President for Nuclear Finance Administration.

9 I am currently a member of the American Institute of Certified
10 Public Accountants and the South Carolina Association of Certified Public
11 Accountants.

12 **Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION IN**
13 **THE PAST?**

14 **A.** Yes. I have testified before the Public Service Commission of South
15 Carolina (the "Commission") in several past proceedings.

16 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

17 **A.** The purpose of my testimony is to present the accounting, budgeting
18 and forecasting information related to the updates in cost schedules
19 proposed in this proceeding. As part of my testimony, I sponsor Exhibit
20 No. __ (CLW-1), which is an updated schedule of capital costs for
21 construction of V. C. Summer Nuclear Station Units 2 and 3 (the "Units").
22 If approved by the Commission, this schedule would become the approved

1 capital costs schedule for the Units under the Base Load Review Act,
2 taking the place of Exhibit F as approved in Order No. 2009-104(A) and
3 Exhibit 2 as approved in Order No. 2010-12. I am also sponsoring Exhibit
4 No. ____ (CLW-2), which shows the relative changes to the capital costs
5 schedule comparing the updated schedule of capital costs to the schedule
6 approved in Order No. ²⁰⁰⁹⁻~~2010~~-104(A) as amended by Order No. 2010-12.
7 These two exhibits are also exhibits to the petition in this docket (the
8 "Petition") with minor updates.

9 **Q. PLEASE EXPLAIN THE VARIATION BETWEEN EXHIBIT NO. ____**
10 **(CLW-1) AND EXHIBIT 1 TO THE PETITION AS FILED.**

11 A. The variation between Exhibit No. ____ (CLW-1) and Exhibit 1 to the
12 Petition as filed reflects the cost of certain change orders (Change Orders
13 No. 9 and 10), which were still under negotiation at the time the Petition
14 was filed, as well as adjustments to the amount of costs not subject to the
15 55%/45% sharing with Santee Cooper. The total amount of the variation is
16 approximately \$13,000. These change orders and other adjustments are
17 discussed in more detail below.

18 **Q. WHAT REQUEST IS THE COMPANY MAKING IN THIS DOCKET**
19 **WITH REGARD TO THE CAPITAL COSTS SCHEDULE?**

20 A. SCE&G is requesting that the Commission approve Exhibit No. ____
21 (CLW-1), as the approved capital costs schedule for the construction of the
22 Units going forward.

1 Q. WHAT IS THE AUTHORITY FOR THIS REQUEST?

2 A. As the South Carolina Supreme Court recognized in its opinion in
3 *South Carolina Energy Users Comm. v. South Carolina Pub. Serv.*
4 *Comm'n*, 388 S.C. 486, 697 S.E.2d 587 (2010) (the "Opinion"), changes to
5 the approved capital costs schedule are authorized under S.C. Code Ann. §
6 58-33-270(E). Under that statute, such modifications to approved schedules
7 of capital costs are appropriate so long as they are not the result of
8 imprudence by the utility.

9 Q. PLEASE EXPLAIN THE CAPITAL COSTS SCHEDULE
10 ADJUSTMENTS THAT ARE PRESENTED IN THE PETITION.

11 A. In the Petition, the Company is proposing the following three
12 adjustments to the schedules that were approved in Order No. 2009-104(A)
13 and updated in Order No. 2010-12.

14 1. Consistent with the Opinion of the South Carolina Supreme Court, the
15 Company has removed from the approved capital costs schedules
16 approximately \$438 million in owner's contingency funds that were
17 included in the cost schedules approved by the Commission in Order
18 No. 2009-104(A) and Order No. 2010-12.

19 2. Consistent with the work the Company has done to refine and update its
20 cost projections since 2006-2008, and consistent with change orders
21 negotiated with Westinghouse/Shaw since that date, the Company has
22 identified and itemized approximately \$174 million in capital costs for

1 the construction of the Units to specific cost categories. Prior to the
2 issuance of the Supreme Court's Opinion, those costs would have been
3 accounted for using a part of the \$438 million that the Commission
4 previously approved in owner's contingency funds.

- 5 3. Consistent with the ongoing refinement of the construction schedule for
6 the Units, the Company has updated its cash flow projections to reflect
7 all timing changes related to the schedule for incurring capital costs that
8 SCE&G has recognized since Order No. 2010-12, including cash flow
9 timing changes as a result of change orders to the EPC Contract. These
10 changes further reflect a truing-up of the cash flow forecast to reflect
11 changes in forecasted construction schedules and milestone completion
12 dates as reflected in the quarterly reports filed with the Commission and
13 South Carolina Office of Regulatory Staff ("ORS").

14 **Q. WHAT IS THE EFFECT OF THESE THREE PROPOSED**
15 **ADJUSTMENTS?**

16 **A.** These changes decrease the approved capital costs schedule for the
17 Units in 2007 dollars from \$4.5 billion as originally approved to \$4.3
18 billion.¹ These changes, along with changes in escalation rates, have

¹ Unless otherwise specified, all cost figures in this testimony are stated in 2007 dollars net of Allowance for Funds Used During Construction and reflect SCE&G's share of the cost of the Units.

1 reduced the cost of the Units from \$6.9 billion, as projected in the financial
 2 schedules that were approved in Order 2010-12, to \$5.8 billion.

3 Chart A

RECONCILIATION OF CURRENT COST PROJECTIONS TO ORDER NO. 2010-12 (\$000)	
Revised Forecast (Exhibit No. __ CLW-1)	\$ 5,838,496
Forecast Order No. 2010-12	\$ 6,875,315
Change	\$ (1,036,819)
Reconciliation:	
Re-Classification of Contingency Dollars	\$ 173,949
Removal of Original Contingency	\$ (438,291)
Removal of Original Contingency Escalation	\$ (216,882)
Change in Project Escalation	\$ (542,631)
Change in AFUDC	\$ (12,964)
Net	\$ (1,036,819)

4
 5 I would note that the current projections reflect current escalation
 6 forecasts which will change quarter-to-quarter as new escalation rates are
 7 published. The current projections do not include any unidentified or un-
 8 identified owner's contingency funds such as those that were contained in
 9 the schedules approved in Order No. 2009-104(A).

10 **Q. PLEASE PROVIDE A BREAKDOWN OF THE \$174 MILLION.**

11 **A.** Exhibit No. __ (CLW-3) shows the \$174 million amount broken
 12 down according to the nine cost categories recognized in the Commission's
 13 BLRA orders and shows 24 individual items that are reflected in the new

1 schedule of forecasted costs. These 24 items generally fall into four
2 separate categories: (1) change orders to the EPC Contract which result in
3 no changes to the overall cost forecast for the project; (2) change orders to
4 the EPC Contract that do affect the forecasted cost of the project; (3)
5 Owners Costs adjustments where due to the nature of the work costs will be
6 assigned to Unit 1, or where SCE&G will not bill Santee Cooper at the full
7 45% rate because the work specifically benefits SCE&G, not the project
8 generally; and (4) updates to the forecast of Owners Costs and
9 Transmission Costs. The details of each of these items will be discussed
10 later.

11 **Q. PLEASE EXPLAIN THE FIRST SET OF THESE ITEMS.**

12 **A.** The first six of these 24 items, Items 1-5 and Item 19, move costs
13 between EPC Cost categories and result in no change in the overall cost of
14 the project, nor do they contribute to the \$174 million amount being
15 presented here for BLRA approval. The reclassifications of costs reflect a)
16 the decision by Westinghouse and Shaw to reallocate the responsibility for
17 certain scopes of work between themselves, b) the decision by Shaw to
18 self-perform work that was originally planned to be performed by
19 subcontractors, or c) the need to correct cost assignments where SCE&G
20 determined that Westinghouse/Shaw had mis-assigned costs between
21 contract cost categories in preparing the cost schedules that accompanied
22 the EPC Contract.

1 Q. PLEASE ELABORATE.

2 A. Items 1-5 represent scopes of work related to module fabrication, on-
3 site module assembly, and the erection of the containment vessel that are
4 being moved between Shaw and Westinghouse as well as certain scopes of
5 work that Shaw intends to self-perform rather than subcontract.

6 Item 19 relates to a mis-assignment of costs in the original EPC
7 Contract categories. Under the EPC Contract, SCE&G agreed to pay costs
8 incurred by Westinghouse/Shaw for certain work done prior to finalization
9 of the EPC contract, specifically site development work and studies done
10 for SCE&G that were related to the contract ("Phase 1A Work"). Item 19
11 reflects the reclassification of the cost of this Phase 1A Work from Target
12 cost categories to the Fixed with No Adjustment cost category to ensure
13 that these costs were not subjected to escalation adjustments as was always
14 the parties' intent. The Phase 1A Work costs approximately \$298,000 and
15 is being transferred to the Fixed with No Adjustment cost category with no
16 net increase in the cost of the project.

17 Q. ARE THESE COST ADJUSTMENTS PRUDENT?

18 A. The cost adjustments shown in Items 1-5 and 19 are prudent and
19 necessary to reflect accurately the current agreements concerning who will
20 perform certain scopes of work or to correct mis-assignments
21 Westinghouse/Shaw made in preparing the cost schedules under the EPC
22 Contract. These changes are a reasonable and prudent part of the

1 management of the EPC Contract. As indicated above, these changes result
2 in no change in the overall project cost estimates.

3 **Q. WHAT IS THE NEXT SET OF ITEMS THAT ARE SHOWN ON**
4 **EXHIBIT NO. __ (CLW-3)?**

5 A. The next set of items, Items 6 – 17, reflects 11 change orders that
6 have been signed or negotiated under the EPC Contract. (Change Orders
7 No. 8 and 11 have been negotiated and are anticipated to be signed in early
8 2011.) One of these change orders, Change Order No. 4, has been
9 superseded by a subsequent change order and will not be executed. Four of
10 these change orders have no cost impact. The remaining six of these
11 change orders (Change Orders No. 2, 3, 7, and 8-10) reflect additional costs
12 incurred to compensate Westinghouse/Shaw for work performed outside
13 the original scope of the EPC Contract. The impacts of these six change
14 orders are set forth as Items 7, 8, 12, 14-16 of Exhibit No. __ (CLW-3).
15 Mr. Byrne testifies to the reasonableness and prudence of the costs
16 reflected in these change orders. I am familiar with these change orders
17 and support his conclusion that they are prudent and reasonable costs of the
18 project.

19 **Q. WHY ARE THERE TWO ENTRIES FOR CHANGE ORDER NO. 8?**

20 A. The financial effects of Change Order No. 8 are listed in two items,
21 Items 13 and 14, to differentiate the effects of the shift in existing costs
22 from Target to Fixed/Firm cost categories, on the one hand, and the

1 payment being made to Westinghouse/Shaw for taking on the additional
2 price risk involved in this shift, on the other.

3 **Q. PLEASE ELABORATE.**

4 A. Under Change Order No. 8, Westinghouse/Shaw agreed to take the
5 majority of the price risk for 11 scopes of work in exchange for a \$10
6 million risk compensation payment. Item 13 on Exhibit No. (CLW-3)
7 shows the shift of \$315 million from the Actual Craft Labor and the Non-
8 Labor Cost categories. These categories are Target categories for which the
9 EPC Contract requires SCE&G to pay invoices based on actual costs.
10 Change Order No. 8 shifted this \$315 million into the Fixed with No
11 Adjustment and the Firm with Indexed Adjustment categories. In these
12 cost categories underlying costs, with or without escalation, are fixed.

13 **Q. DOES THIS SHIFT CHANGE THE COST OF THE PROJECT?**

14 A. No. As shown on Item 13, this shift of \$315 million into Fixed/Firm
15 cost categories involves no net increase in the forecasted cost of the project.

16 **Q. WHAT DOES ITEM 14 REPRESENT?**

17 A. Item 14 accounts for the \$10 million payment negotiated by SCE&G
18 to induce Westinghouse/Shaw to assume the additional price risk associated
19 with these 11 scopes of work. This amount represents a 3.2% cost paid to
20 shift the price risk to Westinghouse on the 11 scopes of works totaling \$315
21 million. This amount is reasonable and prudent given the benefits
22 involved.

1 Of course, it remains possible that change orders or unanticipated
2 conditions could still occur in the scopes of work that have been transferred
3 to Fixed/Firm categories. But the risk that these scopes of work will
4 require more labor, materials or other expenses for reasons that do not rise
5 to the level of a change order at SCE&G's expense have been contractually
6 shifted to Westinghouse/Shaw.

7 **Q. IN ADDITION TO PRICE PROTECTION FOR SCE&G AND ITS**
8 **CUSTOMERS, CAN YOU QUANTIFY OTHER SPECIFIC**
9 **BENEFITS FROM CHANGE ORDER NO. 8?**

10 **A.** Yes. As a part of Change Order No. 8, Westinghouse/Shaw has
11 agreed to forego escalation after August 2010 on \$69 million of the \$315
12 million of the Change Order No. 8 EPC Contract costs. Using the three-
13 year average Handy which an escalation rate of 3.89%, the Company has
14 conservatively estimated the amount of escalation cost avoided to be \$8.6
15 million.

16 As Mr. Byrne testifies, moving the scope of work related to the
17 Heavy Lift Derrick ("HLD") to the Firm with Indexed Adjustment cost
18 category has resolved a potential dispute concerning payment responsibility
19 for the cost of the HLD compared to the cost of two smaller Lampson
20 Cranes. The Lampson Cranes were identified in the EPC Contract as the
21 heavy lift equipment that would be used on the project. However, Shaw
22 chose to use a single HLD which is more expensive but, according to Shaw,

1 results in offsetting efficiencies to the project. Shaw's initial proposal was
2 for SCE&G to absorb the increased cost of the HLD to the extent that those
3 costs would have exceeded the costs that would have been incurred for the
4 use of the two Lampson Cranes. As a result of Change Order No. 8, Shaw
5 has agreed to fix the key cost items for the HLD. This eliminates a
6 potential legal dispute as to payment responsibility for the increased costs
7 associated with the HLD. SCE&G's customers benefit because the project
8 will have the use of the HLD at the current price of the two smaller
9 Lampson cranes.

10 **Q. WHAT WAS THE ALTERNATIVE TO A NEGOTIATED**
11 **SETTLEMENT OF THIS DISPUTE?**

12 **A.** The alternative to a negotiated settlement to this dispute would have
13 been to arbitrate the crane issue as provided for in the EPC Contract. In
14 that arbitration the parties would have been required to pay arbitration panel
15 costs and fees, expert witnesses' costs and fees, and legal fees associated
16 with the proceedings. The arbitration would have been very complex since
17 it would have involved quantifying future hypothetical costs for the
18 Lampson cranes versus future projected costs for the HLD and would have
19 required a comparative analysis of the additional operating efficiencies
20 from having a single, very large, rail-mounted derrick versus two, smaller
21 crawler-mounted cranes. An unfavorable outcome to the arbitration could

1 have increased SCE&G's EPC Contract costs even further. Change Order
2 No. 8 eliminates the risk of each of these potentially negative outcomes.

3 **Q. BEYOND AVOIDING ARBITRATION RELATED TO THE HLD,**
4 **ARE THERE OTHER BENEFITS TO THIS ASPECT OF CHANGE**
5 **ORDER NO. 8?**

6 A. Yes there are. As Mr. Byrne testifies, by agreeing to the terms we
7 proposed in Change Order No. 8, Shaw has taken the financial risk that the
8 HLD may need to be disassembled and reassembled on a new foundation
9 before fuel may be loaded into Unit 2. SCE&G estimates the cost of any
10 such relocation could exceed \$5 million, which is a cost that
11 Westinghouse/Shaw would likely have tried to bill to SCE&G under the
12 EPC Contract but for Change Order No. 8.

13 **Q. ARE THERE OTHER POTENTIAL BENEFITS TO CHANGE**
14 **ORDER NO. 8?**

15 A. Yes. In addition to the benefits listed above, transferring these 11
16 scopes of work to Fixed/Firm cost categories reduces the need for the New
17 Nuclear Deployment ("NND") team to oversee and audit the cost aspects of
18 this work, which results in savings to SCE&G in personnel and resources.
19 SCE&G will audit all work and supporting documentation related to this
20 work to ensure quality work is done and all milestones are met. However,
21 where Fixed/Firm costs are involved, the level of auditing for cost issues is
22 greatly reduced since the underlying costs are borne by

1 Westinghouse/Shaw. We conservatively estimate the value of the
2 incremental resources that would have been necessary to ensure prudent
3 oversight of the costs related to these 11 scopes of work to exceed \$1
4 million.

5 **Q. PLEASE EXPLAIN THE ITEM THAT IS SHOWN ON EXHIBIT**
6 **NO. __ (CLW-3), LINE 17 AS "CHANGE ORDER #11 SCHEDULE**
7 **IMPACT STUDY."**

8 **A.** As Mr. Byrne testifies, Change Order No. 11 reflects the cost of a
9 study that Westinghouse/Shaw is undertaking to develop two alternative
10 construction schedule scenarios and to identify the associated costs of each
11 scenario assuming that the Combined Operating License ("COL") for the
12 project is issued in late 2011 or early 2012.

13 **Q. PLEASE ELABORATE**

14 **A.** The projected date for the Nuclear Regulatory Commission ("NRC")
15 to issue the COL is late 2011 or early 2012. This impacts the critical path
16 of the project, so a decision must be made as to how to deal with this delay.
17 The Company can either keep the current substantial completion date of
18 April 2016 for Unit 2, and compress the construction schedule to meet this
19 date, or the Company can agree to allow the construction schedule to be
20 moved out and move the substantial completion date for Unit 2
21 accordingly. As Mr. Byrne indicates, Westinghouse/Shaw is paying one-
22 half of the cost of this study. This change order does not in any way

1 address the question of who is responsible for the incremental cost
2 associated with the delay. Responsibility and cost assignment for any
3 construction schedule impact of a COL delay will be discussed after
4 SCE&G receives the study results and decisions are made about how to
5 proceed.

6 **Q. WILL THE COST OF THE STUDY AFFECT THE FORECASTED**
7 **COST OF THE UNITS?**

8 A. Conducting the study will not affect the forecasted cost of the Units.
9 The study is being paid out of Time and Materials cost under the EPC
10 Contract. SCE&G believes that it can manage its Time and Materials
11 budget category to allow the costs of the study to be absorbed without
12 affecting the overall budget for this category.

13 **Q. ARE THE COSTS INVOLVED HERE REASONABLE?**

14 A. Yes. SCE&G participated in developing the costing assumptions
15 and the budget resulting in the forecasted \$412,500 cost for this study and
16 has determined them to be reasonable.

17 **Q. PLEASE EXPLAIN THE ITEM THAT IS SHOWN ON EXHIBIT**
18 **NO. __ (CLW-3), LINE 18 AS "COST TRANSFERRED TO UNIT 1-**
19 **ALT A/C LINE."**

20 A. The Unit 1 Switchyard has been reconfigured to allow the new Units
21 to be folded onto the grid. As part of that reconfiguration, a new power
22 feed will be established for Unit 1. The alternative power feed provides an

1 operating and safety benefit to Unit 1. Item 18 contains a \$352,000
2 reduction in the cost forecast for Units 2 & 3 in recognition of the fact that
3 a part of the Unit 1 Switchyard work benefits Unit 1 through the
4 establishment of this alternative power feed. The costs associated with this
5 work were transferred to a capital work order for Unit 1 after they were
6 incurred. Item 18 reflects the removal of the appropriate share of
7 associated costs of this work from the work order. This adjustment reflects
8 a prudent and appropriate adjustment in the cost forecasts which reduces
9 the overall cost forecast for the new nuclear project.

10 **Q. PLEASE EXPLAIN THE ITEM THAT IS SHOWN ON EXHIBIT**
11 **NO. __ (CLW-3), LINE 20 AS "SWITCHYARD NOT SPLIT 55/45."**

12 **A.** In preparing the 2006-2008 cost estimates for the Units, SCE&G
13 projected that the Units' Joint-owner, Santee Cooper, would pay a 45%
14 share of the EPC Contract cost associated with the entire scope of work for
15 the Units 2 & 3 Switchyard. However, SCE&G determined that certain
16 costs included in that scope of work do not benefit the project in general so
17 much as they support construction of new transmission lines for SCE&G's
18 transmission system, which is SCE&G's individual payment responsibility.
19 (Both SCE&G and Santee Cooper are building transmission lines to take
20 power from the Unit 2 & 3 Switchyard to their systems, and both are
21 paying 100% of their individual costs.) A comprehensive review of the
22 Switchyard design in light of these issues is ongoing, as are negotiations

1 between SCE&G and Santee Cooper concerning the amount of any
2 adjustments that need to be made. The amount set forth in this item is a
3 reasonable, prudent and necessary adjustment in the cost forecast.

4 **Q. WHAT IS THE TOTAL NET ADJUSTMENT TO THE EPC**
5 **CONTRACT COST FORECASTS AS A RESULT OF ITEMS 1-20**
6 **ON EXHIBIT NO. __ (CLW-3)?**

7 A. Items 1-20 on Exhibit No. __ (CLW-3) reflect the EPC cost changes
8 that the Company is requesting the Commission to approve. They total
9 approximately \$16 million of the total request.

10 **Q. PLEASE EXPLAIN THE OWNERS COSTS CHANGES SHOWN ON**
11 **EXHIBIT NO. __ (CLW-3), LINES 21-23.**

12 A. The second category of items, Items 21-23 on Exhibit No. __ (CLW-
13 3), shows the changes in Owners Costs forecasts as a result of the Owners
14 Costs budgeting and other reviews of Owners Costs that SCE&G has
15 undertaken since the 2006-2008 time period. Those lines show that the
16 total amount of newly identified and itemized Owners Costs, as reflected in
17 the schedules proposed for approval here, is \$145 million.

18 **Q. HOW WERE THE CHANGES IN OWNERS COSTS FORECASTS**
19 **IDENTIFIED?**

20 A. These costs were identified as a result of preparing very detailed
21 budgets by cost center and resource code for the nine remaining years of the
22 NND project. They also reflect the identification of certain Owners Costs

1 items for which Santee Cooper should not be billed by SCE&G. These
2 amounts relate to such things as costs associated with SCE&G's investor-
3 relations, public relations, legal and tax consulting and regulatory oversight
4 functions supporting the project. These costs are reasonable, prudent and
5 necessary costs of the project and are appropriate responsibilities for
6 SCE&G given SCE&G's status as a regulated, investor-owned utility.
7 However, these are not costs that we can reasonably require Santee Cooper
8 to pay.

9 **Q. WHAT AMOUNT OF THE \$145 MILLION ADJUSTMENT IN THE**
10 **OWNERS COSTS FORECASTS IS ASSOCIATED WITH THESE**
11 **NON-SHARED COSTS?**

12 A. Approximately \$4 million of the \$145 million adjustment is
13 associated with costs that SCE&G can no longer expect will be shared with
14 Santee Cooper. The amount set forth in this item is a reasonable, prudent
15 and necessary adjustment in the cost forecast.

16 **Q. WHAT ABOUT THE REMAINING \$141 MILLION INVOLVED IN**
17 **THE ADJUSTMENT TO OWNERS COSTS FORECASTS?**

18 A. The remaining \$141 million reflects SCE&G's share of costs that
19 have been identified through the review of actual Owners Costs
20 expenditures to date and through the preparation of detailed budgets for the
21 Owners Costs.

1 Q. AS A MATTER OF BACKGROUND, WHAT TYPES OF EXPENSES
2 ARE INCLUDED IN OWNERS COSTS?

3 A. Owners Costs include costs SCE&G will incur in overseeing the
4 construction project; in recruiting, hiring and training staff for the Units; in
5 preparing written operating procedures for all aspects of Unit operations,
6 maintenance, safety and security; in accepting, testing and maintaining the
7 systems and components of the Units as they are completed and turned over
8 to SCE&G pending completion of each Unit as a whole; in obtaining
9 licenses and permits for the project; in start-up testing of the Units as they
10 are completed; in providing the materials and supplies needed for
11 maintenance of plant systems up to the date of commercial operations; and
12 in conducting start-up activities. Owners Costs also include a number of
13 construction related items like workers' compensation insurance for all
14 contractors and subcontractors, payment of miscellaneous taxes including
15 real property and sales taxes, and certain preconstruction costs.

16 Q. PLEASE EXPLAIN HOW THE INITIAL FORECAST OF THE
17 COST OF THESE ACTIVITIES WAS PREPARED.

18 A. As Mr. Byrne testifies, the Owners Costs estimates contained in the
19 original 2008 BLRA application were based on information supplied by
20 Westinghouse/Shaw and other nuclear technology suppliers, information
21 obtained through the prospective owners of Westinghouse AP1000 units,
22 information obtained from licensing consultants and derived from

1 SCE&G's experience with V. C. Summer Unit 1, and information obtained
2 from overseeing major utility construction programs for other plants.
3 Based on information from these sources, SCE&G created a forecast of
4 Owners Costs in 2006-2008 while it was evaluating nuclear and non-
5 nuclear generation options and negotiating the terms of the EPC Contract.
6 That forecast was reflected in Exhibit F to the initial BLRA application and
7 was reviewed and approved in the proceedings leading up to Order No.
8 2009-104(A).

9 **Q. HOW WAS THE CURRENT BUDGET FOR THE COST OF THESE**
10 **ACTIVITIES PREPARED?**

11 A. The current Owners Costs forecast reflects more than two years of
12 work that SCE&G has done to build a budget for Owners Costs on a cost-
13 center by cost-center basis. This budget also reflects SCE&G's actual
14 experience in managing this project since 2008.

15 **Q. PLEASE EXPLAIN HOW THIS BUDGET WAS CREATED.**

16 A. SCE&G initially created the NND team in 2006. From that point
17 forward until the EPC Contract was signed in May of 2008, the NND team
18 was charged with evaluating nuclear technology and vendors and
19 negotiating the EPC Contract. After SCE&G signed the EPC Contract,
20 SCE&G began expanding the NND team to support the licensing,
21 construction and start-up of the Units and financial oversight of the project.
22 At that time, the NND team began detailed planning and budgeting for its

1 work over the upcoming 11 years which included compiling a bottom-up
2 budget for Owners Costs to replace the forecasts contained in the 2006-
3 2008 project estimates.

4 **Q. WHAT HAS GONE INTO THIS BUDGETING PROCESS?**

5 A. Creating these bottom-up budgets has required long-term, focused
6 efforts including the work of Company managers, analysts and accounting
7 personnel representing 130 individual cost centers. This work has resulted
8 in the identification and itemization of the \$145 million in Owners Costs
9 for which BLRA approval is being requested in this proceeding.

10 In many cases, the detailed work necessary to create these budgets
11 could not begin until key leadership was in place in the NND organization
12 to oversee and plan for the work. For example, our NND Operational
13 Readiness General Manager, Mr. David Lavigne, was assigned to that
14 position in 2010. One of his first priorities was to review the preliminary
15 staffing, hiring and training plans to ensure that a full cadre of thoroughly-
16 trained, operating personnel would be in place to support the testing and
17 start-up of Unit 2 and Unit 3 and to accept the security, testing and
18 maintenance responsibility for major systems as turnovers occur throughout
19 the construction process. Mr. Lavigne came to NND from a leadership role
20 at V. C. Summer Unit 1 and he has more than 38 years of experience in
21 nuclear operations and in recruiting and training the personnel needed to
22 operate and maintain nuclear systems. Experience and insight such as his

1 were required to create staffing, recruiting and training plans for Units 2 &
2 3 that go beyond the initial forecast. In addition, a reliable schedule for
3 accepting the turnover of completed systems and conducting testing
4 activities could not be created until Westinghouse/Shaw created its site-
5 specific integrated construction and testing schedule. Westinghouse/Shaw
6 provided SCE&G with this schedule in April of 2009. The staffing plan, of
7 course, depends on that schedule.

8 **Q. COULD YOU ELABORATE FURTHER ON THIS PROCESS FOR**
9 **CREATING A BOTTOM-UP STAFFING PLAN?**

10 A. Take, for example, maintenance and operation of a particular plant
11 system. Part of the budgeting process for Owners Costs is to determine the
12 costs and resources needed to create written maintenance schedules and
13 operating procedures for that part of the plant. Then, based on those
14 schedules and procedures, the Company can confirm or adjust its estimate
15 of the number of people it will need in that area for plant operations and
16 maintenance and what skills they will require. Based on information as to
17 the required skills of these employees, the Company can determine the
18 training plans required for those positions. Creating and delivering those
19 training plans become another element of work to be scheduled and costs to
20 be budgeted. Then, based on the system's turnover, testing and start-up
21 schedule provided by Westinghouse/Shaw, the Company can determine
22 when it needs those people to be in place, trained and ready to assume

1 responsibilities for the system. Recruiting and hiring plans are then created
2 to have the right people come into the project at the right time so that they
3 can be fully trained by the time they are needed to support operating and
4 maintenance activities. This sort of detailed planning and budgeting is
5 complex and is not something that it is reasonable to do before a
6 construction contract is signed.

7 **Q. IN PREPARING THE CURRENT OWNERS COSTS BUDGET,**
8 **HOW DID YOU OBTAIN BUDGET INFORMATION FROM NON-**
9 **NND AREAS?**

10 A. The information for non-NND cost centers directly providing
11 support to the project was obtained by identifying the cost centers in
12 SCE&G and SCANA that have played or are expected to play a significant
13 role in the nuclear deployment effort and requiring them to provide detailed
14 budgets for their activities in support of the project through 2019.
15 Currently, there are approximately 111 such cost centers that have been
16 identified and that have provided budget information for this part of the
17 Owners Costs budget. These cost centers include such groups as SCANA
18 Audit Services, Legal, Treasury, Environmental, Forestry Services, Risk
19 Management and Insurance, Facilities Management, and multiple groups
20 within current Nuclear Operations (*i.e.*, groups like Unit 1 Health Physics
21 that may assist on an as-needed basis in creating staffing plans and writing
22 operating procedures for parts of Unit 2 & 3 operations). SCANA made the

1 decision early in the process not to permit non-task specific time or cost
2 allocations from groups outside of NND but to require such groups to
3 directly assign time and costs to the project based on actual work performed
4 for NND. In addition, Nuclear Finance required all SCANA cost centers
5 which anticipated direct charges of \$5,000 or more per year to the project to
6 prepare and submit a detailed budget by resource code and by year for their
7 work.

8 **Q. HOW DID YOU ASCERTAIN THE REASONABLENESS OF THE**
9 **AMOUNTS BEING BUDGETED THROUGH THIS PROCESS?**

10 **A.** The NND team carefully reviewed the budget forecasts being
11 provided by these cost centers areas to ensure that the costs they included
12 were reasonable and appropriate. We did so based on i) our experience
13 with budgets for Unit 1 and other operating entities of SCANA, ii) our
14 experience with other major construction projects, and iii) the track record
15 which we had compiled of the actual level of services being provided to the
16 project between May 2008 and September 2010. Since the inception of this
17 project, the NND team has been very diligent in reviewing all costs charged
18 to the project from non-NND areas. These charges are reviewed each
19 month to ensure that charges are accurate and appropriate. Our joint-
20 owner, Santee Cooper, has an equal interest in making sure that all charges
21 are appropriate and reviews these charges independently on a monthly
22 basis.

1 Q. IS A COPY OF THE CURRENT OWNERS COSTS BUDGET
2 AVAILABLE?

3 A. A copy of the current Owners Costs budget is attached to my
4 testimony as Exhibit No. __ (CLW-4). Consistent with Mr. Marsh's
5 testimony, I would emphasize that this budget will be updated on an on-
6 going basis as the project proceeds.

7 Q. COULD YOU PROVIDE A BUDGET SUMMARY FOR OWNERS
8 COSTS?

9 A. Yes. A summary Owners Costs budget is set forth below:

10

Chart B

OWNERS COSTS Actuals Sept 2010 + Projections (\$000)	
Owners Costs Category	Actuals / Projections
NND Management Administration	45,250
NND Licensing, Permits, & Inspections	58,622
NND Legal	2,801
NND Business & Finance	4,238
NND Finance Admin	7,059
NND Engineering	29,658
NND Construction	33,054
NND QA	8,792
NND Training	24,133
NND Operations	40,153
Operational Readiness	82,208
Direct SCANA Services	25,822
VC Summer Unit 1	627
Insurance	58,864
Sales Tax	9,369
Total	\$430,649

1 We anticipate this to be the format in which Owners Costs information for
2 the project will be presented going forward.

3 **Q. ARE YOU CONTINUING TO PREPARE OR UPDATE**
4 **INFORMATION USING THE FORMAT OR CATEGORIES**
5 **PRESENTED IN THE 2006-2008 OWNERS COSTS FORECASTS?**

6 A. SCE&G manages and operates the project based on the detailed cost
7 center budgets reflected in Exhibit No. __ (CLW-4). SCE&G uses this
8 budget to drive accountability for costs across the project team. We are not
9 preparing or updating information using the format or categories used in
10 preparing the 2006-2008 Owners Costs forecasts. Those categories are not
11 based on cost centers to the same degree that the current budget is based on
12 cost centers. They do not match the way that the NND teams are now
13 organized nor do they reflect the cost centers around which the NND
14 finances are organized and reported.

15 **Q. HOW DO YOU PLAN TO GO ABOUT UPDATING THE CURRENT**
16 **BUDGET?**

17 A. Our present plans are to undertake a comprehensive budget update
18 effort once per year using the current cost center based budget. Each cost
19 center with charges in excess of \$5,000 per year will be asked to update and
20 itemize their budgets going forward for the remaining life of the project.
21 We will conduct a review of these forecasts each year that would be similar

1 to the review of the initial budget information that has been described
2 above.

3 **Q. WHAT DOES EXHIBIT NO. __ (CLW-4) SHOW?**

4 A. Exhibit No. __ (CLW-4) is a summary budget for the 19 NND cost
5 centers and for the other 111 non-NND cost centers that we currently
6 anticipate charging costs exceeding \$5,000 per year to the project. The
7 costs shown on this budget are broken down by individual resource codes
8 for each of the 130 NND and non-NND cost centers.

9 **Q. WHAT IS THE BACK-UP MATERIAL FOR THIS BUDGET?**

10 A. For each of the entries here, there is a separate set of schedules that
11 breaks these summarized costs down by month for 2010 and 2011 and by
12 year for the period of 2012-2019. Each cost center manager has developed
13 a budget based on his or her professional judgment and experience. These
14 budgets are supported by staffing and training plans, current corporate
15 salary structures, outside services budgets, and other cost center specific
16 budget documents as available. These detailed cost center budgets roll up
17 and support the overall budget set forth here.

18 **Q. WHO CAN REVIEW THIS BACK-UP INFORMATION**
19 **SUPPORTING THE CURRENT BUDGET?**

20 A. We are making the above-mentioned detailed cost center budgets
21 and supporting documentation information available at the site to ORS.
22 Because of the commercially sensitive nature of much of this information,

1 and because in some cases this information contains data about individual
2 employees' salaries, we are asking parties to sign confidentiality
3 agreements if they wish to inspect this data at the construction site.

4 **Q. IS IT POSSIBLE TO MAKE A COMPARISON BETWEEN THE**
5 **2006-2008 FORECAST AND THE CURRENT BUDGET?**

6 A. Yes. It is possible to make a comparison between the two budgets.
7 Such a comparison involves two budget forecasts that use very different
8 forecasting approaches (one being initial forecasts, the other developed
9 from a bottom-up budget approach) and with very different approaches to
10 organizing the data for the costs they present. A comparison between them
11 can only be done by reallocating the costs in the current budget into the
12 categories which were used in developing the 2006-2008 Owners Costs
13 forecasts as approved in Order No. 2009-104(A), as amended in Order No.
14 2010-12. This reallocation of costs is a difficult process that requires
15 informed accounting and operational judgment. It involves assigning cost
16 center budgets details between cost categories rather than by functional
17 areas, and in some cases requires splitting cost center data between multiple
18 cost categories. However, despite its limitations this comparison does
19 provide a means to highlight the principal drivers underlying the changes in
20 Owners Costs forecasts. Nonetheless, it is not possible to force the
21 comparative analysis of the two budget forecasts to a level of detail greater
22 than what is contained in the 2006-2008 forecast.

1 Q. WHAT DOES THIS COMPARISON SHOW?

2 A. Chart C, below, presents this comparative analysis using the 12 cost
3 categories used in the 2006-2008 Owners Costs forecast. The results are as
4 follows:

5

Chart C
SCE&G OWNERS COSTS
Budget Comparative Analysis²
(\$000)

	Original Budget	Updated Budget	Variance
1. Onsite Training & Startup / SCE&G Labor	124,088	188,130	64,042
2. Insurance	57,750	58,863	1,113
3. Sales Tax	9,350	9,352	2
4. Licensing / Permits / NRC Inspection Fees	36,850	51,556	14,706
5. General & Administrative	22,002	74,706	52,704
6. Non-EPC Construction	9,490	20,820	11,331
7. Spare Parts	8,326	8,326	-
8. Plant Equipment, Tools, Maint Materials, Consumables, & Supplies	16,390	16,215	(175)
9. NuStart	-	2,235	2,235
10. Met Tower, Plant Site Layout, Pre EPC Project Management	447	447	-
11. Real Estate/Property Taxes	275	-	(275)
12. Electricity	1,100	-	(1,100)
Total	286,068	430,649	144,583

² Due to rounding, the amounts contained in Chart C may not precisely reflect the amounts specified in other exhibits.

1 Q. PLEASE EXPLAIN THE COST DRIVERS RELATED TO THE
2 CHANGE FOR "ONSITE TRAINING & STARTUP / SCE&G
3 LABOR."

4 A. The costs represented here are the NND group's direct labor costs
5 projections resulting from the detailed budgeting process for construction
6 project oversight and operational readiness described earlier. Several items
7 are driving the current change in budgeted costs. One driver is the
8 commitment SCE&G made early in this process to hire and deploy an NND
9 team that would be fully capable of overseeing the construction, operational
10 readiness, licensing and financial aspects of the project. Such oversight
11 requires an extensive team of skilled employees with experience in such
12 specialized areas as nuclear engineering, nuclear construction management,
13 nuclear permitting, nuclear training and staffing, nuclear process
14 engineering, and nuclear operations. Such oversight also requires
15 personnel experienced in project and financial accounting, auditing, and
16 project and contract compliance controls for major construction projects.
17 Staffing such a group requires compensation sufficient to hire and retain
18 individuals with these qualifications. The NND team currently employs
19 approximately 140 people. The cost of recruiting and deploying such a
20 team for the nine-year construction and startup period is reflected in the
21 current forecast of the costs of Onsite Training & Startup / SCE&G Labor.

1 The Onsite Training & Startup / SCE&G Labor cost category also
2 reflects the cost of recruiting, hiring, training and employing the personnel
3 who will operate and maintain the Units as responsibility for them is turned
4 over to SCE&G by Westinghouse/Shaw. The skill levels and training
5 levels required for these jobs are exacting and the nuclear operating
6 standards and staffing requirements that apply to them continue to evolve
7 and become more demanding with time. In light of these training
8 requirements, the staff to be trained will have to be recruited earlier than
9 had been anticipated in 2006-2008 and kept on the nuclear payroll longer
10 than initially anticipated to support the lengthy training protocols required
11 for many of these positions.

12 **Q. PLEASE ELABORATE.**

13 **A.** The number of people required to provide oversight for construction
14 and to operate the Units when built has increased. The areas with the most
15 significant increase are nuclear security and trainers, including reactor
16 operator trainers. In addition, personnel on the NND teams will need to be
17 available to develop and document the approximately 155 plant programs
18 (such as the Thermal Performance Program, the Equipment Reliability
19 Program, and the System Status Control Program) and the approximately
20 3,500 individual procedures that will be required to operate and maintain
21 the Units. In addition, given the difficult qualification standards trainees
22 will have to meet, the hiring count for certain highly-regulated disciplines

1 will need to be expanded to provide for those hires who ultimately fail to
2 qualify or leave the Company as a result of normal attrition. The project
3 management team has already experienced significant challenges attracting
4 qualified candidates for most of the technical positions.

5 For all these reasons, the current budget for Onsite Training &
6 Startup / SCE&G Labor costs for the project is updated by \$64 million. As
7 indicated above, the costs contained in this category have been carefully
8 reviewed and evaluated. They are based on detailed staffing, hiring and
9 training plans, as well as actual recruiting and hiring experience. These
10 costs are reasonable, necessary, and prudent costs of the project.

11 **Q. PLEASE EXPLAIN THE COST DRIVERS RELATED TO**
12 **"INSURANCE."**

13 **A.** The Insurance cost category includes costs associated with workers'
14 compensation insurance for all workers on site, builder's risk insurance for
15 the site and transportation risk insurance for equipment being shipped to the
16 site. The estimated cost of the insurance for the project itself has not
17 changed significantly since the 2006-2008 Owners Costs forecast. The
18 difference between the current Owners Costs budget and the original
19 forecast reflects the budgeted costs for the creation, staffing and
20 administration of a workers' compensation claims function for the nine-
21 year life of the construction project. Estimates for the cost of this claims
22 function were not included in the original Owners Costs forecast that was

1 created in the 2006-2008 time period. The estimate for the workers'
2 compensation claims function is approximately \$1.1 million in total for the
3 remaining nine years of construction and startup. This is a reasonable,
4 necessary, and prudent cost of the project.

5 **Q. PLEASE EXPLAIN THE COST DRIVERS RELATED TO THE**
6 **"SALES TAX COST CATEGORY."**

7 A. The variance in the Sales Tax category reflects administrative costs
8 for taxes that will not be shared with Santee Cooper as the project's joint-
9 owner. As I have discussed, certain scopes of work were originally
10 budgeted to be shared with Santee Cooper, at its 45% joint-ownership rate.
11 We have determined that some sales tax administrative costs benefit are
12 related to these amounts and should not be charged to Santee Cooper. The
13 amount not recoverable from Santee Cooper is \$2,000. This is a
14 reasonable, necessary, and prudent adjustment to the cost of the project.

15 **Q. PLEASE EXPLAIN THE COST DRIVERS RELATED TO**
16 **"LICENSING / PERMITS / NRC INSPECTION FEES."**

17 A. There are two principal drivers of the Licensing / Permits / NRC
18 Inspection Fees cost category: a) the increased time and effort that is being
19 required to monitor and conduct NRC licensing activities and to respond to
20 Requests for Additional Information from the NRC, and b) the increased
21 cost of NRC inspection fees. The total amount of the change in this cost
22 category is estimated to be \$15 million. These are reasonable, prudent and

1 necessary costs of licensing and permitting the construction and operations
2 of the Units.

3 **Q. PLEASE EXPLAIN HOW NRC LICENSING IS AFFECTING**
4 **OWNERS COSTS BUDGETS.**

5 A. Units 2 and 3 represent two of the four AP1000 units that are in
6 active licensing and construction at this time. They are likely to be among
7 the first new nuclear units that will be built in the United States since the
8 1980s. The level of regulatory scrutiny they are receiving appropriately
9 reflects this fact.

10 At the time the EPC Contract was signed, the AP1000 design was
11 fully licensed though Design Control Document ("DCD")-15. Thereafter,
12 Westinghouse submitted new design control documents (DCD Revs-16-18)
13 to strengthen the shield building design against aircraft impacts and to
14 make other modifications to improve the design. The result has been a
15 more extensive, demanding and costly NRC licensing process than was
16 anticipated in 2006-2008.

17 **Q. PLEASE EXPLAIN HOW NRC INSPECTION FEES ARE**
18 **AFFECTING OWNERS COSTS FORECASTS.**

19 A. The anticipated expense for NRC inspection fees has risen
20 significantly based on guidance received from the NRC since the 2006-
21 2008 forecasts were developed. The NRC has informed SCE&G that the
22 number of inspections that they will conduct and the costs that they will

1 charge for resident inspectors have increased. These increases are reflected
2 in the amount of the adjustment to this cost category.

3 **Q. PLEASE EXPLAIN HOW THE COST CATEGORY FOR**
4 **"GENERAL AND ADMINISTRATIVE COSTS" IS AFFECTING**
5 **THE OWNERS COSTS FORECAST.**

6 A. General & Administrative costs represent the direct support provided
7 to the NND team from non-NND cost centers within SCE&G and SCANA.
8 The original forecast for these costs was based upon an estimated
9 percentage of certain Owners Costs items that was included in the 2006-
10 2008 budget projections. As originally envisioned, Owners Costs would
11 serve as an overhead component for services like information technology
12 and human resources support for these items. However, the complexity and
13 resource requirements of the NND project are proving to be greater than
14 was estimated in the 2006-2008 time frame. The forecasted costs for
15 support to the NND team from other SCANA cost centers have increased to
16 reflect the size and complexity of the project. As indicated above, the
17 current costs budgets are based on detailed cost-center by cost-center
18 budgets from each non-NND cost center that will provide direct support to
19 the project in amounts exceeding \$5,000 per year. The impact of the
20 change in the forecasted cost of these items is \$53 million. The
21 reasonableness of this amount is documented by the detailed cost-center
22 budget on which it is based. The General and Administrative costs in

1 question are reasonable, prudent and necessary costs of constructing and
2 licensing the Units.

3 **Q. PLEASE EXPLAIN HOW THE "NON-EPC CONSTRUCTION"**
4 **COST CATEGORY IS AFFECTING THE OWNERS COSTS**
5 **BUDGETS.**

6 A. The Non-EPC Construction category of Owners Costs primarily
7 reflects the costs associated with the construction of the new Nuclear
8 Operations Building ("NOB"), the new addition to the Nuclear Learning
9 Center and the refurbishment of the existing Nuclear Training Center. The
10 2006-2008 cost forecasts for the NOB and the addition to the Nuclear
11 Learning Center were based on estimates which have now been adjusted to
12 reflect actual designs for the buildings and construction bids from M. B.
13 Kahn contractors. The current budget is based on actual design documents.
14 Since the development of the 2006-2008 forecast, the decision has been
15 made to house the NND team for construction oversight in an existing
16 structure. This structure has previously served as the nuclear training
17 center and had for the most part been vacated. The cost of refurbishing and
18 redesigning the facility was approximately \$1.9 million more than
19 originally forecasted. The updated budget for this category of costs for
20 these non-EPC structures has been adjusted by approximately \$11.3
21 million. These costs are reasonable, necessary, and prudent costs of the
22 project.

1 Q. PLEASE EXPLAIN HOW THE "SPARE PARTS BUDGET"
2 AFFECTS THE OWNERS COSTS FORECASTS.

3 A. At present, no change is reflected in the budget for the Spare Parts
4 cost category. As Unit 2 nears completion, Westinghouse will be required
5 to provide SCE&G with a list of critical and required spare parts to which
6 SCE&G should maintain current access to ensure reliable operation of the
7 Units. These spare parts requirements will be evaluated based on the
8 likelihood of failure of particular components of equipment and the lead-
9 times involved in obtaining or fabricating replacement parts if they are not
10 maintained in spare parts inventories. Based on the list prepared by
11 Westinghouse, SCE&G will decide which spare parts to store on site and in
12 what quantities. SCE&G will make these evaluations in consultation with
13 other prospective owners of AP1000 units and will seek to expand the pool
14 of spare parts available and reduce the costs of maintaining them by sharing
15 access to certain spare parts among the group.

16 Q. WHEN WILL THAT PROCESS TAKE PLACE?

17 A. This evaluation of the need for spare parts and options for stocking
18 those that are required will take place prior to the startup of Unit 2. Once
19 the spare parts list is developed, the NND team will begin the process of
20 pricing the required units of property based on their costs in the market.
21 Once that is done, the budgets will be updated to reflect any adjustments if
22 necessary.

1 Q. PLEASE EXPLAIN HOW THE COST CATEGORY FOR "PLANT
2 EQUIPMENT, TOOLS, MAINTENANCE MATERIALS,
3 CONSUMABLES, & SUPPLIES" IS AFFECTING THE OWNERS
4 COSTS FORECASTS.

5 A. The cost category for "Plant Equipment, Tools, Maintenance
6 Materials, Consumables, & Supplies" is where the project will account for
7 the purchase of tools, equipment, materials and supplies that must be
8 available to support startup and operations and maintenance of the Units or
9 as major component systems turned over to SCE&G by
10 Westinghouse/Shaw. The budgets for these costs are being updated by the
11 NND team and only items related to information technology, networking,
12 security, telecommunication and health physics equipment have been fully
13 reviewed at this time. Based on that review, the budget for this category is
14 being reduced by approximately \$175,000. The review of the other items
15 in this cost category will continue and further adjustments will be made if
16 necessary.

17 Q. PLEASE EXPLAIN WHAT THE COST CATEGORY "NUSTART"
18 REPRESENTS.

19 A. SCE&G is a member of NuStart Development, LLC ("NuStart"),
20 along with nine other entities that are interested in having Westinghouse
21 and General Electric design standard plants licensed by the NRC. Through
22 NuStart, the entities interested in AP1000 units have been coordinating

1 efforts and sharing expenses in obtaining an AP1000 Reference Plant COL
2 from the NRC. This Reference Plant COL will serve as the basis for all
3 subsequent site-specific COLs for follow-on plants. Specifically, the
4 NuStart AP1000 member group is sharing the cost of the Reference Plant
5 portions of the COL application for the Vogtle units, which is the
6 Reference Plant for this purpose. These costs include consulting,
7 engineering and legal costs associated with the development of the
8 Reference Plant COL application.

9 **Q. HOW HAVE ESTIMATED NUSTART COSTS CHANGED?**

10 A. The estimated NuStart costs have increased by approximately \$2.2
11 million as a result of changes in forecasted proceeds from the sale of the
12 Reference Plant COL application to other potential AP1000 utilities. This
13 is a reasonable, necessary and prudent adjustment to the cost of the project.

14 **Q. PLEASE EXPLAIN WHAT THE COST CATEGORY "MET
15 TOWER, PLANT SITE LAYOUT, PRE-EPC PROJECT
16 MANAGEMENT" REPRESENTS.**

17 A. The cost category for Met Tower, Plant Site Layout, Pre-EPC
18 Project Management represents actual costs that had been expended early in
19 the construction process for building the onsite meteorological data tower
20 needed for environmental characterization of the site, for physically laying
21 out the plant site before construction, and for managing certain aspects of
22 the project before the EPC Contract was signed. The amounts involved in

1 this cost category were known amounts at the time the EPC Contract was
2 signed. As a result, there is no change or update to the budgeted amounts
3 for these items.

4 **Q. PLEASE EXPLAIN WHY COST CATEGORY "PROPERTY**
5 **TAXES" IS BEING REDUCED TO ZERO.**

6 A. This cost category contains the cost of property taxes anticipated to
7 be paid on real property forming part of the project. The 2006-2008
8 Owners Costs forecast assumed that approximately \$275,000 in property
9 taxes would be paid over the course of the construction project. A fee in
10 lieu of taxes agreement was reached with Fairfield County. Under this
11 agreement, no additional property taxes will be charged during construction
12 beyond those already being recovered through the current Unit 1 property
13 tax bill. For that reason, the entire \$275,000 amount reflected in the
14 original forecast is being removed from the budget.

15 **Q. PLEASE EXPLAIN WHY COST CATEGORY "ELECTRICITY" IS**
16 **BEING REDUCED TO ZERO.**

17 A. The 2006-2008 Owners Costs forecast reflected approximately \$1.1
18 million for the fuel cost associated with the electricity to be used in
19 construction of the Units. Consistent with the treatment of other company-
20 use power, accounting rules requires the construction power here to be
21 charged to a company-use account. Hence it will not be recorded to the

1 work order for the Units. For that reason, SCE&G has not included the
2 \$1.1 million charge in the current Owners Costs budget.

3 **Q. IN SUMMARY, WHAT DOES THIS COMPARATIVE ANALYSIS**
4 **SHOW CONCERNING THE REASONABLENESS AND**
5 **PRUDENCY OF THE CURRENT CONSTRUCTION COST**
6 **ESTIMATES?**

7 A. As discussed above, the current Owners Costs budget reflects
8 detailed cost-center based budgeting involving approximately 130
9 individual cost centers. The budgets for each have been carefully reviewed
10 and evaluated for reasonableness. This analysis confirms the
11 reasonableness of the adjustment in Owners Costs for the categories listed
12 above, and supports the conclusion that the updated Owners Costs budget is
13 a reasonable and prudent estimate of the cost associated with this
14 construction project.

15 **Q. PLEASE EXPLAIN THE ITEM THAT IS SHOWN ON EXHIBIT**
16 **NO. (CLW-3), LINE 24 AS "TRANSMISSION - UNIT 1**
17 **SWITCHYARD REDESIGN."**

18 A. Item 24 shows the costs associated with the additional engineering,
19 testing and documentation work that must be done to support the nuclear
20 industry standards for the work required in the Unit 1 switchyard to
21 integrate Units 2 & 3's output onto the transmission grid. This amount is

1 net of other items that reduce the forecast of transmission costs. Mr. Byrne
2 testifies to the nature and prudence of this cost. The amount of this
3 adjustment was based on an engineering estimate from Shaw that has been
4 determined by SCE&G and to be a reasonable estimate for the work to be
5 done.

6 **Q. PLEASE EXPLAIN HOW CHANGES TO THE CONSTRUCTION**
7 **SCHEDULE AND TIMING OF CASH FLOW ARE REFLECTED IN**
8 **THESE PROPOSED COST SCHEDULES.**

9 A. On a quarter-by-quarter basis, SCE&G adjusts its cash flow
10 forecasts to account for all changes in the expected timing of construction
11 costs. This includes acceleration or delay in milestone dates and associated
12 payments, changes in the pace of work, contractor invoicing, and other
13 changes. Such changes are reflected in the schedules presented here. They
14 are the result of normal refinements and adjustments made to the
15 construction schedule for the Units and are reasonable, prudent and
16 necessary adjustments. The effect of them is that the net forecasted cash
17 flow schedule has shifted further into the future by a small amount. This
18 updating of cash flow timing does not modify or alter the \$174 million of
19 newly identified and itemized costs which are presented here. However, the
20 new cash flow does change the amount of time before certain payments are
21 anticipated to be made, and so, other things being equal, would change the
22 amount of escalation realized on the project. The effects of these changes

1 in project cash flow are reflected in the escalated figures shown in Exhibit
2 No. ____ (CLW-1).

3 **Q. HAS THE COMPANY RECALCULATED THE ANALYSIS OF**
4 **RATE IMPACTS FROM THE UNITS TO REFLECT THE**
5 **ADJUSTMENTS REQUESTED IN THIS DOCKET?**

6 A. Yes. The recalculated figures are contained in Exhibit No. ____
7 (CLW-5). This exhibit is an updated schedule of the anticipated revenue
8 requirements and rate adjustments related to construction of the Units over
9 the life of the construction project which incorporate the reclassifications of
10 costs set forth in Exhibit No. ____ (CLW-1) and Exhibit No. ____ (CLW-2) but
11 otherwise reflects all assumptions as to fuel costs, production tax credits
12 and other matters contained in Exhibit G to South Carolina Electric & Gas
13 Company's Request For Approval Of Revised Rates, Docket No. 2010-157-
14 E.

15 **CONCLUSION**

16 **Q. WHAT ARE YOU REQUESTING THIS COMMISSION TO DO?**

17 A. The Company is requesting that the Commission approve, pursuant
18 to S.C. Code Ann. § 58-33-270(E), the updated capital costs schedule in
19 Exhibit No. ____ (CLW-1) as the approved schedule of capital costs for the
20 Units, subject to adjustment for escalation and net of AFUDC as provided
21 for in Order No. 2009-104(A).

22

1 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

2 A. Yes, it does.

4/4/11 Hearing Testimony of Carlette L. Walker [2010-376-E]

1 **BY MR. ZEIGLER:**

2 **Q** Ms. Walker, have you prepared certain supplemental
3 direct testimony that's been prefiled in the record of
4 this case, of approximately seven pages?

5 **A** I did.

6 **Q** And are there any corrections to that testimony?

7 **A** There are no corrections.

8 **Q** And attached to that testimony there are two exhibits,
9 are there not?

10 **A** That's right.

11 **Q** And there's a CLW-1 Updated and CLW-2 Updated, and I
12 believe there's a confidential and a non-confidential
13 version of CLW-1 Updated, is that correct?

14 **A** That's correct.

15 **Q** Ms. Walker, if I were to ask you the questions contained
16 in this supplemental direct testimony today, would your
17 answers from the stand be the same?

18 **A** They would be.

19 **MR. ZEIGLER:** Mr. Chairman, we would move Ms.
20 Walker's supplemental direct testimony into the
21 record at this time, and similarly we would move
22 the exhibits with the confidential version of
23 Exhibit -1 being moved into the record under seal.

24 **CHAIRMAN HOWARD:** Ms. Walker's supplemental
25 direct testimony will be read into the record as if

1 given orally from the stand. And Exhibits -1 and
2 -2, both confidential and public version --

3 MR. ZEIGLER: Thank you, Mr. Chairman.

4 CHAIRMAN HOWARD: -- will be Hearing Exhibit
5 No. 6.

6 [WHEREUPON, Hearing Exhibit No. 6,
7 including Public and Confidential
8 Portions, was marked and received in
9 evidence.]

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24 [PREFILED SUPPLEMENTAL DIRECT TESTIMONY OF
25 CARLETTE L. WALKER FOLLOWS AT PGS 264-270]

1 SUPPLEMENTAL DIRECT TESTIMONY OF

2 CARLETTE L. WALKER

3 ON BEHALF OF

4 SOUTH CAROLINA ELECTRIC & GAS COMPANY

5 DOCKET NO. 2010-376-E

6
7 Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

8 A. My name is Carlette L. Walker. My business address is 1162 State
9 Highway 213, Jenkinsville, South Carolina.

10 Q. ARE YOU THE SAME CARLETTE WALKER WHO HAS
11 PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS
12 DOCKET?

13 A. I am.

14 Q. WHAT IS THE PURPOSE OF THIS SUPPLEMENTAL
15 TESTIMONY?

16 A. The purpose of my testimony is to update the capital cost schedules
17 which were included as Exhibit 1 to the Petition in this matter and as
18 Exhibit No. ____ (CLW-1) that was submitted as part of my direct testimony
19 in this docket. The updated version of these schedules is Exhibit No. ____
20 (CLW-1 updated). In addition, as attachments to my direct testimony, I
21 also include Exhibit No. ____ (CLW-2) that showed the variance between
22 Exhibit No. ____ (CLW-1) and the similar schedule approved in Order No.

1 2010-12. The updated version of Exhibit No. ____ (CLW-2) is attached as
2 Exhibit No. ____ (CLW-2 updated). It also includes a second section, Table
3 2 to this Exhibit, which provides the variation between Exhibit No. ____
4 (CLW-1 updated) and Exhibit No. ____ (CLW-1).

5 **Q. WHY ARE THESE CAPITAL COST SCHEDULES BEING**
6 **UPDATED?**

7 A. The forecast contained on Exhibit No. ____ (CLW-1 updated) reflects
8 the most recent capital cost forecast from Westinghouse/Shaw which is the
9 forecast that includes actual data for the fourth quarter of 2010 and updated
10 forecasts as of January 2011.

11 **Q. ON WHAT DATA WERE THE FORECASTS PROVIDED WITH**
12 **THE PETITION BASED?**

13 A. The cost forecasts contained in Exhibit 1 to the Petition in this
14 proceeding were based on the capital cost schedule Westinghouse/Shaw
15 provided to SCE&G near the close of the third quarter of 2010 to support
16 the November filing date for the Petition in this proceeding. That
17 information was supplemented with the Owners Costs forecast and
18 Transmission Cost forecasts that were current at the end of the third quarter
19 of 2010. We further supplemented this information with information
20 related to the costs and cost shifts associated with Change Orders 8-11 to
21 the EPC Contract that had been negotiated since the close of the quarter.

1 Q. ON WHAT DATA WERE THE FORECASTS PROVIDED WITH
2 YOUR DIRECT TESTIMONY BASED?

3 A. Exhibit No. __ (CLW-1) was based on the cost forecast provided by
4 Westinghouse/Shaw near the close of the third quarter 2010 with very
5 minor adjustments as discussed in my direct testimony. Those adjustments
6 involved further refinement to the costs and cost reassignments related to
7 Change Orders 8 and 9, and further refinements to the calculation of costs
8 that are not anticipated to be shared 55%/45% with our co-owner Santee
9 Cooper.

10 Q. WHAT ARE THE PRINCIPAL CHANGES IN THE FORECAST
11 THAT IS NOW BEING PRESENTED IN EXHIBIT NO. __ (CLW-1
12 UPDATED)?

13 A. Exhibit No. __ (CLW-1 updated) does not change the overall capital
14 cost of the project in 2007 dollars, which remains the same \$4.3 billion cost
15 that was presented in Exhibit No. __ (CLW-1), nor does it change the relief
16 requested in this docket which is a \$174 million adjustment in the approved
17 cost schedules in 2007 dollars. The changes in Exhibit No. __ (CLW-1
18 updated) are changes in the timing of costs and cost categories to which
19 costs comprising that \$4.3 billion are assigned. Specifically, Exhibit No.
20 __ (CLW-1 updated) reflects the following adjustments:

21 1. After further review of the cost reassignments made by
22 Change Order 8, Westinghouse/Shaw has determined that a net amount of

1 \$13 million that was included in the Non-Labor Cost category should be
2 reassigned to the Actual Craft Wages cost category and other adjustments
3 needed to be made in the timing of future costs to reflect the reallocation of
4 costs from Target categories to Firm/Fixed cost categories. The
5 reallocation of forecasted cash flows between categories and the
6 rescheduling of the forecasted project cash flows between years does not
7 change the overall cost of the project. They do, however, change the
8 categorization and timing of anticipated expenditures. These are
9 reasonable, necessary and prudent adjustments to properly account for the
10 changes in how \$315 million in costs will be handled under Change Order
11 8. I would note that Westinghouse Shaw is continuing to work on the
12 proper accounting for the changes in the categorization and timing of costs
13 related to this Change Order and SCE&G is carefully reviewing all the
14 changes being made to insure that they fully comply with the terms of the
15 EPC Contract and Change Order 8.

16 At the close of the fourth quarter of 2010, \$67 million in
17 funds that were scheduled to be spent during that year were not spent.
18 Those unspent funds are being rolled forward into future years. This
19 reallocation of unexpended funds is a reasonable, necessary and prudent
20 adjustment to the cost forecast and does not change the overall cost of the
21 project in 2007 dollars.

1 Q. DOES THE INFORMATION CONTAINED IN EXHIBIT NO. __
2 (CLW-1 UPDATED) ALSO REFLECT NEW ALLOWANCE FOR
3 FUNDS USED DURING CONSTRUCTION ("AFUDC") RATES AND
4 UPDATED ESCALATION FORECASTS?

5 A. Yes. Exhibit No. __ (CLW-1 updated) reflects current escalation
6 forecasts and updated AFUDC forecasts.

7 Q. PLEASE EXPLAIN THE CHANGES.

8 A. Under Order No. 2009-104(A), the one-year escalation index applies
9 to the 12 months that follow the currently completed quarter and the five
10 year index applies for the period that follows those 12 months. With the
11 completion of the fourth quarter of 2010, the applicable escalation index for
12 the fourth quarter of 2011 shifted from the five-year average to the one-year
13 average, which is lower. As a result of this reduction in the applicable
14 escalation rate for that quarter, as well as changes in the timing of cash
15 flows as indicated on Table 2 of Exhibit No. __ (CLW-2 updated), the
16 escalation forecast for the project is less than what was forecasted when my
17 testimony was initially filed. The escalation forecast for the project has
18 dropped by \$4.5 million as shown on line 25 of that Table.

19 In addition, a new AFUDC rate is computed at the close of each
20 calendar year. When this was done at the end of 2010, the rate dropped
21 from 7.1% to 5.87%. As shown on that Exhibit No. __ (CLW-2 updated),
22 at Table 2, this change in the AFUDC rate, when coupled with the changes

1 in the timing of cash flows under the new forecast, reduces the AFUDC
2 forecast by \$47.1 million, as shown on line 31 of that Table.

3 **Q. WHAT IS THE NET EFFECT OF THE CHANGES ON THE**
4 **FORECAST OF GROSS CONSTRUCTION COSTS?**

5 A. As shown on line 33 of Table 2 of Exhibit No. ____ (CLW-2
6 updated) the gross construction forecast for the Units is now \$54.6 million
7 less than as was computed in January 2011 when I prepared my initial pre-
8 filed testimony. I would note that these changes are due to changes in
9 escalation forecasts and AFUDC rates which will change regularly over the
10 course of the project. Normal changes in these rates are likely to create
11 both increases and decreases in the cost forecasts over the life of the
12 project.

13 **CONCLUSION**

14 **Q. WHAT ARE YOU REQUESTING THIS COMMISSION TO DO?**

15 A. As indicated above, the changes in the schedules of capital costs for
16 the project reflected on Exhibit No. ____ (CLW-1 updated) represent
17 reasonable, necessary and prudent changes in these forecasts. For that
18 reason, the Company is requesting that the Commission approve, pursuant
19 to S.C. Code Ann. § 58-33-270(E), the updated capital costs schedule in
20 Exhibit No. ____ (CLW-1 updated) as the approved schedule of capital costs
21 for the Units, subject to adjustment for escalation and net of AFUDC as
22 provided for in Order No. 2009-104(A).

1 BY MR. ZEIGLER:

2 Q Ms. Walker, will you provide a summary of your testimony
3 for the Commissioners?

4 A I will. Good afternoon, Mr. Chairman and members of the
5 Commission.

6 My testimony presents the accounting, budgeting,
7 and forecasting support for the updates to cost
8 schedules that are proposed in this proceeding. As part
9 of my testimony, I sponsor Exhibit CLW-1 that's been
10 updated, which is an updated schedule of capital costs
11 for the construction of the units. The cash flow
12 forecast contained in Updated Exhibit CLW-1 reflects the
13 most recent capital cost forecast from Westinghouse and
14 Shaw. It includes actual data through fourth quarter of
15 2010 and updated forecast as of January of 2011. If
16 approved by the Commission, this schedule would become
17 the approved capital cost schedule for the units under
18 the Base Load Review Act. I am also sponsoring Updated
19 Exhibit CLW-2, which shows the relative change in the
20 capital cost schedule when compared to the current
21 approved schedule of capital costs. As explained in my
22 direct testimony and supplemental direct testimony,
23 these two exhibits are updated versions of exhibits to
24 the petition in this docket.

25 The company is proposing three categories of

1 adjustments to the current capital cost schedule.

2 First, the company has removed approximately \$438
3 million in owners' contingency funds that were initially
4 approved for this project. As Mr. Marsh explained, this
5 adjustment was made to comply with the ruling issued by
6 the South Carolina Supreme Court in the appeal of the
7 original Base Load Review order.

8 Second, the company has continued to refine and
9 update these cost projections since they were made in
10 the 2006-2008 time period. SCE&G has updated its
11 estimates and budgets for owners' costs and transmission
12 costs associated with the project. In addition, ten
13 change orders have been negotiated to the EPC contract,
14 six of which impact the project costs. Based on these
15 updates and change orders, the company has identified
16 and itemized approximately \$174 million in capital costs
17 for the project. It is now seeking Commission approval
18 to include these costs in the approved capital cost
19 schedules for the project. Prior to the Supreme Court's
20 opinion that I just mentioned, these costs would have
21 been accounted for by using part of the \$438 million of
22 owners' contingency.

23 Third, the company has updated its cash flow
24 projections to reflect all changes in the cash flow
25 schedule for the project that SCE&G has recognized since

1 Order No. 2010-12. These changes reflect a truing up of
2 the cash flow forecast based on updates to the
3 construction schedules as they have evolved. These
4 changes to cash flow schedules do not change the cost of
5 the project in 2007 dollars.

6 In my testimony, I discuss the change orders
7 negotiated under the EPC contract. My testimony
8 supplements the description of the change orders
9 provided by Mr. Byrne. It also provides a detailed
10 discussion of the nature and financial impact of each of
11 these change orders. For the reasons discussed in my
12 testimony, the costs associated with the change orders
13 are reasonable, necessary, and prudent costs of the
14 project.

15 My testimony also discusses the adjustments to the
16 capital cost schedules resulting from the reallocation
17 of costs that SCE&G originally intended to share 45
18 percent with our joint owner Santee Cooper. Based on
19 SCE&G's ongoing evaluation and review of project
20 budgets, SCE&G determined that certain costs that we
21 initially planned to share with Santee Cooper primarily
22 supported the construction of new transmission lines for
23 SCE&G's transmission system. We determined that we
24 could not expect Santee Cooper to pay part of those
25 costs. In addition, as we broke our initial estimates

1 of owners' costs down into specific activities, we
2 concluded that we could not ask Santee Cooper to pay a
3 portion of our internal costs, like legal and tax
4 consulting costs, investor relations costs, and
5 regulatory oversight costs, because these costs do not
6 directly benefit Santee Cooper. For that reason, Santee
7 Cooper will not be billed for any share of these costs.
8 SCE&G has made a \$9 million adjustment to the cost
9 forecast to account for a proper allocation of these
10 costs.

11 In addition, SCE&G has identified and itemized a
12 \$145 million adjustment to owners' cost forecasts as a
13 result of the detailed planning and budgeting that SCE&G
14 has undertaken since the initial cost estimates were
15 made in the 2006-2008 time period. Since 2008, SCE&G
16 has been working to prepare detailed budgets for owners'
17 costs by cost center and resource code for the remaining
18 years of the project. These bottom-up budgets replace
19 the initial owners' cost estimates. Preparing these
20 budgets has required many months of effort from
21 managers, analysts, and accounting personnel,
22 representing 130 individual cost centers throughout
23 SCANA. This detailed budgeting work as required the
24 availability of the integrated site-specific
25 construction schedule for the project, which

1 Westinghouse and Shaw provided to us in April of 2009.
2 This work has also required the creation of detailed
3 hiring, staffing, and training schedules based on the
4 construction schedule, and on the creation of operating
5 and maintenance processes and procedure documents for
6 the units. In many cases, these staffing and operating
7 plans could not be created until key leadership was in
8 place in the new nuclear deployment, or NND,
9 organization to oversee that work. Throughout this
10 process, the NND team carefully reviewed the budget
11 forecast being provided by these cost centers to ensure
12 that the costs they included were reasonable and
13 appropriate. The NND team made this evaluation based on
14 its experience with unit 1 costs and budgets, its
15 experience with other nuclear and utility construction,
16 and its experience in managing the current project
17 between May of 2008 and September of 2010. Since the
18 inception of this project, the NND team has been very
19 diligent in reviewing all costs charged to the project
20 from non-NND areas. The data compiled to date -- to
21 date provides a basis by which project's future costs,
22 which we do not have and which we did not have in 2008.
23 A copy of this detailed budget is attached as an exhibit
24 to my testimony. It has been carefully reviewed by the
25 ORS. We have offered to provide any party access to the

1 backup documentation and information to support the
2 costs reflected in this budget during the discovery
3 phase of this proceeding. In my testimony, I provide a
4 comparison between the current project budgets and those
5 initially approved in the Base Load Review order.

6 The most significant cost driver identified in that
7 analysis is the additional cost of hiring, training, and
8 maintaining the NND team to oversee the project, and the
9 staff that will operate and maintain the units and major
10 component systems as they are turned over to SCE&G. To
11 support the needs of the project, the number of
12 personnel, the length and the depth of training, and the
13 required level of skill and experience of those hired
14 have increased. In addition, given the required depth
15 of training and the schedule on which SCE&G will assume
16 responsibility for the activities and system, the hiring
17 dates for many positions have been accelerated. All of
18 these things have increased direct costs associated with
19 the NND project.

20 The second key driver is increased support costs
21 for the NND project, which are directly related to the
22 size of the NND team that is being supported, how long
23 that team will be in place, and the complexity of the
24 project.

25 The third most significant driver is the additional

1 cost of licensing, permitting, and NRC inspection fees.
2 These costs reflect the NRC's decision to increase the
3 costs and number of NRC inspections and the increased
4 complexity of the NRC licensing process, given the DCD
5 amendments proposed by Westinghouse after the EPC
6 contract was signed. These and other cost drivers are
7 discussed in more detail in my testimony. In each case,
8 this analysis confirms the reasonableness of these
9 adjustments in owners' costs and supports the conclusion
10 that the updated owners' cost budget is a reasonable and
11 prudent estimate of the costs associated with this
12 project.

13 Finally, SCE&G has adjusted its cash flow forecast
14 to account for changes in the expected timing of
15 construction costs, as the construction schedule and
16 equipment fabrication schedules have evolved. These
17 changes include accelerations or delays in milestone
18 dates and associated payments, changes in the pace of
19 work, changes in the timing of anticipated contractor
20 invoicing, and other changes. They are the result of
21 normal refinements and adjustments to the construction
22 schedules and are reasonable, prudent, and necessary
23 adjustments.

24 In conclusion, the company requests that the
25 Commission approve the updated capital cost schedules in

1 the Updated Exhibit CLW-1 as the approved schedule of
2 capital costs for the units, subject to the adjustment
3 for escalation and net of the AFUDC as provided for in
4 Order No. 2009-104(A). The adjustments presented in the
5 petition and included in the updated capital cost
6 schedule are reasonable, prudent, and necessary changes,
7 and are not the result of imprudence on the part of the
8 Commi- -- of the company. We would ask the Commission
9 to review the settlement entered into by SCE&G, and that
10 the Commission accept it as resolving the issues in this
11 case.

12 That concludes my summary.

13 MR. ZEIGLER: Mr. Chairman, Ms. Walker is
14 available for questions from Mr. Elliott and the
15 Commission.

16 CHAIRMAN HOWARD: Mr. Elliott?

17 CROSS EXAMINATION

18 BY MR. ELLIOTT:

19 Q Ms. Walker, would you turn, please, in your prefiled
20 testimony, to page six. You've got a Chart A.

21 A Okay.

22 Q And I think I understand this, for the most part, but
23 just please help me.

24 A Okay.

25 Q In this chart, you are showing the revised forecast at

1 \$5.8 billion, correct?

2 A Billion, that's right.

3 Q And that's a reduction of about \$1 billion and some
4 change from the previous forecast; is that correct?

5 A \$1 billion --

6 Q \$1 billion. Did I --

7 A -- that's correct.

8 Q Okay. And as I understand it, is the driver there that
9 the inflation, at least recently, the *Handy Whitman*
10 inflation factors have sort of driven those prices down,
11 those costs down?

12 A Well, I mean, that's the whole point of the
13 reconciliation below the bolded \$1 million -- \$1
14 billion.

15 Q All right.

16 A There are a number of different elements that are
17 driving a billion-dollar change. Just like you
18 indicated, escalation has impacted it; escalation has
19 driven the price down by the \$216 million and the \$542
20 million.

21 Q I see.

22 A And then we've also removed the original contingency of
23 \$438 million. We've revised the AFUDC by \$12 million,
24 and then we have incorporated the increased owners'
25 costs by the \$174 million.

1 Q All right, thank you. And I understand the contingency
2 of \$438, and again, because of the way that initial
3 order was designed, actually the inflation on that 438
4 was going to be about \$217 million.

5 A Based on the *Handy Whitman Index*, that's correct.

6 Q Yes. All right, ma'am. And then -- okay. But the
7 still good news is that the total project cost at this
8 point is down by another \$1/2 billion or so, by virtue
9 of the *Handy Whitman* indices --

10 A That's correct.

11 Q -- going downward?

12 A That's correct.

13 Q And I'm curious, do you see that -- how long do you
14 foresee our luck holding out there?

15 A I definitely would not be in comfort with speculating as
16 to what the *Handy Whitman* is going to do in the future.

17 Q All right. Well, I was hoping it would be good news.
18 Now, let me draw your attention to the line that says,
19 "Reclassification of contingency dollars," and that's
20 the \$174 million we're here for today, I assume,
21 correct?

22 A That's correct.

23 Q Now, I want to ask you about that phrase you use,
24 "reclassification," and I'm wondering does that term --
25 what do you mean by that term "reclassification"?

1 A It's our contention that this Commission approved the
2 original contingency of \$438 million. Our budget was
3 built with the anticipated level of contingency that was
4 approved. And our understanding of the BLRA and the
5 actual Supreme Court order would indicate now that, to
6 the extent that we've identified and itemized costs that
7 would have otherwise come out of contingency, that it
8 would be our responsibility to bring it before the
9 Commission and that the Commissioners would then approve
10 those itemized costs. So we consider this a
11 reclassification of what used to be an approved
12 contingency for the project.

13 Q I'm not an accountant, but is that sort of an accounting
14 term you're using?

15 A No.

16 Q When you say "reclassification"?

17 A No. I mean it's reclassification --

18 Q It's just a term you're using for the purposes of this
19 proceeding?

20 A I mean, I think it would be a term that most people
21 would use in a variety of different forums.

22 Q But you're not aware of that term being found in the
23 Base Load Review Act, are you?

24 A No.

25 Q So you use this term again -- this "reclassification" --

1 I think in this paragraph 18 of your petition, but
2 basically what you're doing is you're asking this
3 Commission to consider these costs afresh and approve
4 them, or perhaps not, correct?

5 A We're asking that they be approved as prudent and
6 appropriate costs for the life of the project.

7 Q Yes, ma'am, thank you. Now, were the Commission to
8 approve the entire \$174 million, some of that, if not
9 all of that amount, would be subject to inflation also,
10 wouldn't it?

11 A Of the 174?

12 Q Yes, ma'am?

13 A It would be subject to inflation to the extent that
14 actual costs incurred were something higher than what
15 was originally built in these 2007 dollars, so that
16 would be correct.

17 Q All right. And would you agree with me that, at least
18 as of February 28, your best estimate of the inflation
19 associated with this \$174 million is \$3,683,000?

20 A I'm not familiar with that number. If you could point
21 to me --

22 Q Well, I am --

23 A -- in my testimony where I might have --

24 MR. ELLIOTT: -- going to, if I may, show her
25 this e-mail from Chad [indicating].

1 MR. ZEIGLER: Certainly.

2 BY MR. ELLIOTT:

3 Q I'm really kind of assuming -- I'm assuming you're the
4 brains of this outfit and that you would be privy --

5 A I would love to think that, but I don't actually believe
6 that. Go ahead.

7 Q -- and that you would be familiar with this. And I show
8 you an e-mail to me from Kenneth Chad Burgess, of
9 February 28th, where you'll see some highlighting. And
10 I've highlighted what I understood the e-mail to suggest
11 was the inflation impact of this \$174 million. And I
12 just -- I ask you if those numbers look familiar to you
13 [indicating].

14 A [Indicating.] I actually am not familiar with the
15 numbers, but I deal with so many numbers, I'm not --
16 that's not to say that I didn't have some input into it.

17 Q Well, I think I'd like to pin that down, if I may. Do
18 you suppose -- would it be difficult for you to,
19 assuming the Commission and your attorneys would
20 authorize it, would it be difficult for your staff to
21 just identify the inflation that you would -- or the
22 escalation, as you prefer to call it, associated with
23 the \$174 million?

24 A Absolutely.

25 MR. ELLIOTT: May I ask that as a late-filed

1 exhibit, if I can put Mr. Burgess or Mr. Zeigler on
2 the spot?

3 MR. ZEIGLER: We'd be happy to, Mr. Chairman.
4 I would note, for the record, that all that
5 inflation is already included in the numbers that
6 are in Ms. Walker's testimony, so it's not
7 something additional to. We can identify it
8 specifically, but it's already incorporated in the
9 numbers that are there in the chart that Mr.
10 Elliott's referring to.

11 CHAIRMAN HOWARD: Okay, if you could just go
12 ahead and identify it.

13 MR. ELLIOTT: I understand what Mr. Ziegler's
14 said to be the case. I just would like it spelled
15 out.

16 CHAIRMAN HOWARD: That'll be Late-filed
17 Exhibit No. 7, Mr. Elliott.

18 MR. ELLIOTT: Thank you.

19 WITNESS: So you want that through the current
20 period? As of today?

21 MR. ELLIOTT: I mean, I think that would be --
22 I think that would be ideal.

23 MR. ZEIGLER: My understanding is the request
24 would be to take the 174 and determine what the
25 escalation impacts over the life of the project

1 would be, associated with that number. If that's
2 correct, then --

3 MR. ELLIOTT: That is correct. I --

4 MR. ZEIGLER: -- that's what -- we'll be happy
5 to do that.

6 MR. ELLIOTT: -- just assumed that perhaps
7 there might be an actual figure. But, yes, that's
8 what I'm looking for, so that there's a match for
9 the ORS and the utility to know what the authorized
10 costs are.

11 WITNESS: Well, and just for clarification,
12 I'd like the Commissioners to understand that, you
13 know, we've got pre-identified indices that is
14 applied to anything that's subject to escalation,
15 but that's not a guaranteed level of expenditure.
16 Our expenditures are going to be what we actually
17 incur. The escalation merely allows you some level
18 of increase to incorporate or to compensate for
19 inflation, but that's not necessarily an indication
20 that that's going to be the level to spend that
21 we'll have.

22 MR. ELLIOTT: Thank you.

23 BY MR. ELLIOTT:

24 Q I did have -- I wanted to -- I thought Mr. Byrne did a
25 very nice job with these change orders, but you have an

1 exhibit that is your -3-C to your direct, and I'm
2 looking at a confidential version, and I'd like to show
3 you on the page what I'm going to ask you about, because
4 if there's a confidential figure here, I don't know that
5 I care that much about the figure. Do you see line
6 number 20 [indicating]?

7 A [Indicating.]

8 Q All right. I'm going to ask you about that, okay? And
9 I don't know that I care -- is that dollar figure a
10 confidential number?

11 A I don't think it would be.

12 Q Well, if you're comfortable using it, fine. I'm not
13 gonna'. The item, it's -3-C, number 20, "Switchyard
14 not split 55/45." Could you explain to me what's going
15 on there in that particular item, please?

16 A Sure. Some of the costs associated with the switchyard
17 are not going to be a 55/45 split. Some of the
18 switchyard costs benefit SCE&G more directly than they
19 do Santee Cooper, so we have entered into what we would
20 consider to be verbal negotiations and come to an
21 agreement on what would be a more fair and equitable
22 sharing of transmission costs. So what you see in
23 Exhibit -3-C of my prefiled testimony is the amount of
24 money that is not -- it's the differential between what
25 we negotiated to split with Santee on the switchyard

1 versus what 45 percent of the switchyard costs would
2 have calculated out to be.

3 So I think the split came out to be somewhere in
4 the neighborhood of 31, 32 percent; our contract with
5 them, as far as output of the two units is 45 percent.
6 So it's the difference between the switchyard increased
7 cost at 31 percent versus that same cost at 45 percent.

8 Q So that's the -- is that -- that figure there on line 20
9 represents a percentage of an increase in costs?

10 A That would be an increase in cost to SCE&G ratepayers --

11 Q Right.

12 A -- based on a more equitable split of the switchyard
13 assets.

14 Q All right. And this is something you've already
15 negotiated with Santee Cooper?

16 A That's right.

17 Q And they've accepted the figure?

18 A We've --

19 Q They've accepted --

20 A -- gone back and forth --

21 Q -- the figure?

22 A -- on numerous occasions in the transmission
23 organization to come up with what both parties feel like
24 is a fair and equitable split.

25 Q All right, ma'am. And then you mentioned a \$9 million

1 figure -- I thought -- in your summary a few minutes
2 ago, about where your ratepayers would take on another
3 \$9 million in costs adjusted from Santee Cooper? Did I
4 understand that correctly?

5 A That's correct.

6 Q And what do those figures involve? What are those
7 costs?

8 A Those are costs that are categorized as part of the
9 owners' costs that we feel like, as well as Santee
10 Cooper, they are not the beneficiary of those costs.
11 It's specific to a regulated utility. They're not
12 regulated in South Carolina, and there are certain other
13 functions that we have that support our being able to
14 sell equity funding into the market to finance the
15 project. So we have identified certain South Carolina
16 fees that we have to pay, treasury functions, public
17 relations costs, some tax consulting fees, that we
18 consider to be the beneficiary is SCE&G and not Santee
19 Cooper, and wouldn't feel like it was appropriate to
20 bill them for their 45 percent of that cost.

21 Q All right, thank you. So it's \$9 million for owners'
22 costs, and it's this figure in line 20 representing, in
23 essence, transmission costs?

24 A Switchyard, yes.

25 Q Okay. Would that be -- I accept your answer. Would

1 that switching be different from transmission?

2 A Yeah. The switchyard is actually a part of the plant;
3 transmission are the lines that move the --

4 Q All right.

5 A -- electricity away from the generating station.

6 Q Okay, thank you. Now, you alluded in your summary, I
7 think, to the fact that -- or at least in your
8 testimony, prefiled testimony -- to the effect that
9 until a reliable schedule for accepting the turnover of
10 completed systems and conducting testing activities
11 could be created by Westinghouse/Shaw, that it would be
12 difficult to determine what your actual owners' costs
13 were.

14 A Uh-huh.

15 Q Is that your testimony?

16 A It is.

17 Q So, therefore, as I understand it, until we got the
18 approved modification of the construction schedule by
19 this Commission last year, it would be -- you could not
20 do your bottom-up budget process?

21 A Well, no. I mean, I think that the schedule -- the
22 actual site-specific construction schedule -- was yet
23 another element of our being able to further refine the
24 owners' costs.

25 Q Okay. Now, I was -- do you recall the hearing held

1 before the Commission -- it was November of 2009 -- on
2 your petition to update construction progress and a
3 request for updates and revisions to schedules related
4 to construction of a nuclear base-load generation
5 facility at Jenkinsville, South Carolina?

6 A I do.

7 Q And you testified at that hearing, correct?

8 A Correct.

9 Q I was at that hearing, and I don't recall your
10 testifying that, once the Commission finalized this
11 schedule, that you were going to have to come back to
12 this Commission to raise owners' costs and other costs
13 for this facility. Did you testify to that at that
14 hearing?

15 A I probably -- I mean, I don't know for certain. I
16 wouldn't expect that I would have. I actually took the
17 assignment to go to the nuclear facility as this VP of
18 Nuclear Finance in the latter part of August of that
19 same year. I had two very specific areas of focus when
20 I initially started getting a feel for where the project
21 team was, one of which was to ferret out an owners' cost
22 that was built from a bottoms-up budget that we
23 reference in my testimony today, and then secondly was
24 to gain an understanding of the systems that the
25 consortium was using to produce billings to SCE&G and

1 Santee Cooper, to make sure that, to the extent they had
2 weak or lacking controls, that we had compensating
3 controls on the project team to make certain that our
4 ratepayers were protected and only paid for those costs
5 that were appropriate under the contract terms.

6 Q Thank you. Do you recall testifying that the
7 modifications to the cash flow schedules, in that
8 hearing, are timing related changes only and do not
9 affect the overall cost of the project in 2007 dollars,
10 before allowance for funds used during construction --
11 AFUDC? Do you recall testifying to that?

12 A I would expect that I would've said that. But again,
13 that's cash flow for EPC contract, and the EPC contract
14 is underpinned by a multitude of cash flows, and they're
15 tied to the construction schedule. So to the extent
16 that in the April 2009 time period, that a more refined
17 site-specific construction schedule was developed, you
18 would expect that the construction cost would also shift
19 and move according to when scopes of work were going to
20 be actually performed. So what we were testifying to at
21 that point was, really, much more focused on the EPC
22 contract cash flow, not on changes in the owners' costs
23 arena at that point.

24 Q Well, thank you for that explanation. Do you recall
25 testifying that the overall cost of the units remains at

1 \$4.5 billion, at the time, as approved in the BLRA
2 order? Do you recall testifying to that, ma'am?

3 A I'd have to review the testimony that we had filed, but
4 that sounds like it would probably be about right.

5 Q Well, if the Commission in its order characterized your
6 testimony to that effect, you wouldn't disagree with the
7 Commission's characterization of your testimony, would
8 you, ma'am?

9 A Not likely.

10 Q And based on your testimony, the Commission found in
11 that order -- Order No. 2010-12 -- that the Commission
12 finds that the requested modifications do not alter the
13 approved total cost of the units of \$4.5 billion, in
14 2007 dollars, net of AFUDC. You recall that finding,
15 because you've studied the order, haven't you?

16 A [Nodding head.]

17 Q All right. So you came in in November 2009 and said
18 that this schedule change was not going to alter the
19 costs, but now you're here today saying that you
20 couldn't determine what your real costs would be until
21 you had the schedule change, aren't you?

22 A Would you repeat that again?

23 Q You testified that changing the schedule would not alter
24 your costs, correct?

25 A It would not alter the costs from the EPC contract,

1 that's right.

2 Q And now you're testifying that you couldn't determine
3 your actual costs, and in particular the owners' and
4 transmission costs, until you had this order in hand.
5 Isn't that your testimony today?

6 A What I said earlier to the Commissioner was, with two
7 and a half, three months under my belt on the project, I
8 had just begun identifying a mechanism by which we would
9 ferret out what would be the appropriate owners' costs,
10 given a, now, site-specific construction schedule and
11 understanding as to who had what responsibility as far
12 as deliverables to the project.

13 Q Thank you. Would you answer my question, please?

14 A You'll have to repeat the question, because I thought I
15 did.

16 Q No, ma'am, I don't think so. Let me read this from page
17 22, lines two through seven of your prefiled testimony,
18 and ask you if they sound familiar --

19 A Of this [indicating] testimony?

20 Q Right here, yes, ma'am. Today.

21 A What page?

22 Q 22, lines two through seven. "In addition, a reliable
23 schedule for accepting the turnover of completed systems
24 and conducting testing activities could not be created
25 until Westinghouse/Shaw created its site-specific

1 integrated construction and testing schedule.
2 Westinghouse/Shaw provided SCE&G with this schedule in
3 April 2009. The staffing plan, of course, depends on
4 that schedule." That's your testimony today, isn't it?

5 A That's correct.

6 Q Yes, sir. Now, as I understand it from Mr. Byrne's
7 testimony and from your testimony as it is now in the
8 record, from 2006 to 2008, SCE&G, through the NND,
9 focused on identifying an appropriate reactor,
10 negotiating the contract, and signing a contract; is
11 that correct?

12 A That would be one of the primary focuses of the NND team
13 at that point, I would agree.

14 Q And again, as Mr. Byrne pointed out and you point out in
15 your testimony, as well, in determining what those costs
16 are, you rely on your company's experience, that of
17 Westinghouse, Mr. Byrne testified AREVA and GE and
18 Bechtel and the other companies such as Southern that
19 were going to build plants, and even the Chinese, relied
20 on all that expertise to determine what your owners'
21 costs were going to be in 2008, correct?

22 A That's correct.

23 Q And we've heard a lot about all the work you all have
24 done to do this bottom-up budgeting since the Base Load
25 Review order was issued in 2009. You've done a lot of

1 work, haven't you?

2 A My team has, yeah.

3 Q Well, and I suspect you have, too. Now, let me ask you
4 if this is your testimony, please -- and just for the
5 sake of ease, I'm looking at page 20 of your prefiled
6 testimony, at line 16 -- "SCE&G initially created the
7 NND team in 2006. From that point forward, until the
8 EPC contract was signed in May 2008, the NND team was
9 charged with evaluating nuclear technology and vendors
10 and negotiating the EPC contract. After SCE&G signed
11 the EPC contract, SCE&G began expanding the NND team to
12 support the licensing, construction, and startup of the
13 units, and the financial oversight of the project. At
14 that time," May of 2008, "the NND team began a detailed
15 planning and budgeting for its work over the upcoming 11
16 years, which included compiling a bottom-up budget for
17 owners' costs to replace the forecasts contained in the
18 2006 to 2008 project estimates." That's your testimony,
19 correct?

20 A We did, that's right.

21 Q So after you signed the EPC contract in May, you started
22 to try to ascertain what your owners' costs for the
23 project were going to be.

24 A Well, there was an estimate at the point that they
25 signed the EPC contract.

1 Q So you had an estimate?

2 A That's right.

3 Q And at the time you signed the contract in May, you also
4 filed your Base Load application in May.

5 A That's right.

6 Q So you went forward on an estimate of your owners' costs
7 in your Base Load application, correct?

8 A That's correct.

9 Q All right. And if I understand your testimony
10 correctly, now that you have a Base Load order, an order
11 revising your Base Load order, and two revised rates
12 orders, your hard work has borne out the fact that
13 building these nuclear plants is more expensive than you
14 thought or estimated in May of 2008, correct?

15 A I would disagree with that. When we originally filed
16 with the BLRA, we had -- and we've talked about this
17 consistently throughout today's hearing -- \$438 million
18 in contingency, and we felt very confident that with a
19 very high-level estimate of owners' costs, and through
20 the use of that contingency, that we would be able to
21 deliver those plants in 2016 and 2019 under those costs.
22 So to characterize it any other way, I think, you're not
23 giving us credit for having the model that included a
24 contingency.

25 Q Well, I'm sorry, because I'm giving you a lot of credit

1 for coming up with the contingency, but that isn't the
2 law, is it?

3 A Subsequent to the BLRA and the order from this
4 Commission, the contingency was repealed.

5 Q Yes, ma'am, I would agree with that.

6 A But also keep in mind that, at the point in time when we
7 were trying to negotiate the contract, it wouldn't be
8 practical to go out and canvass across all of the
9 different areas of SCANA to try to get input into what
10 they thought their level of support was going to be for
11 an EPC contract at the time when you were still trying
12 to ferret out who had what responsibility for the
13 deliverables under the EPC contract to develop those two
14 units. So you're kind of trying to put the cart before
15 the horse. You've got to understand the basis of the
16 contract, execute the contract, bring that before this
17 Commission in a timely manner because of how material
18 that is to a utility that you regulate. And then, at
19 that point, once everyone understands who has what
20 responsibility, you're then able to go back and
21 communicate to various pieces and parts of SCANA, and
22 tell them what we needed them to bring to the project
23 and deliver, as compared to what Westinghouse and Shaw
24 had to deliver.

25 Q Okay. So the focus is, you get the contract approved,

1 you know, in February or March of 2009, and then you
2 figure out what it's going to cost you to build the --
3 to operate the owners' cost; is that your testimony?
4 A No. You figure out what is included in the contract,
5 and then, based on a very small team understanding what
6 was deliverable by the owner, you do some high-level
7 estimates of what those owners' costs are, and then,
8 now, with a much larger team and a more vast group
9 understanding who owes what to the development of those
10 two units, you're able to go out to the various SCANA
11 services areas and say, "We need you to develop the
12 fiber-optic lines and the fiber-optic huts, to be able
13 to support the communications throughout Unit 2 and Unit
14 3." That's different than, "What would you do to
15 provide communications for two nuclear units?" They
16 have a very specific function, and then they are able to
17 identify the assets and the labor that was required to
18 install those.

19 Q May I invite your attention to page 29 of your prefiled
20 testimony? There's a Chart C. And tell me when you're
21 there.

22 A I'm there.

23 Q All right. Now, I talked to Mr. Byrne about this a
24 little bit, but I guess you've got four columns. The
25 first column is numbered 1 through 12, and these are the

1 owners' cost categories where you're seeking some
2 adjustment. Some go down, some disappear, but for the
3 most part you're seeking an upward adjustment. The
4 second column says "Original budget," and is that a fair
5 characterization based on your testimony, or should we
6 call it really your original estimates?

7 A Either way.

8 Q All right.

9 A A budget is nothing but an estimate.

10 Q Okay. And so then the third column is your updated
11 budget, the fourth column your variance?

12 A That's correct.

13 Q And so if I understand the testimony in the file, number
14 one, the training, the original estimate was \$124
15 million. This NED team, the small team with -- in spite
16 of its reliance on Westinghouse and AREVA and GE and
17 Bechtel and 40 years of nuclear experience,
18 underestimated the very expensive proposition of
19 training its employees for two never-operated generators
20 by \$64 million; is that correct?

21 A Well, you have to pay attention to where the slash is.
22 It says "On-site training and startup/SCE&G labor." So
23 we're not dealing with just strictly training and
24 startup; we're talking about SCE&G labor. And, in fact,
25 we did miss that amount, but also you have to build into

1 the equation that there have been rules that have, you
2 know, more or less matured. We knew the fatigue rule
3 was in place. Whether it was going to be interpreted
4 and applied for a construction facility was yet to be
5 known. Since the 2006-2008 time period, we do know that
6 the fatigue rule does apply to a construction facility,
7 so that has significant impact in what your level of
8 labor is going to be for the security during
9 construction. So there are various pieces and parts
10 that are driven based on ongoing changes in the
11 regulation, as well as our gaining an understanding of
12 the technology.

13 Q But SCE&G is not surprised that training and startup and
14 labor is very expensive for a nuclear plant.

15 A No, they're not surprised by that.

16 Q All right. I'm curious. It's a small amount, but do I
17 understand the testimony in number two to be that you
18 forgot the workers' comp?

19 A Workmen's comp is not \$1 million, if that's what you're
20 trying to imply that \$1 million is.

21 Q Well, I'm mainly trying to find out if you forgot the
22 workmen's comp?

23 A No, we did not forget --

24 Q Okay, good.

25 A -- the workmen's comp.

1 Q Thank you. I feel better. Number four, licensing,
2 permits, NRC inspection fees. Your NND team came
3 closest, I guess, of the several large ones there;
4 they're only \$15 million short. You're not surprised --
5 SCE&G is not surprised that this project, this novel
6 project, is going to be very costly to get licensed, is
7 it?

8 A Is it surprised that it's going to be costly?

9 Q Yeah.

10 A No, they're not surprised.

11 Q Now, I do want to ask about general and administrative,
12 and you've got that nice long list there in your
13 testimony, but I'm really more intrigued by your
14 testimony -- your direct testimony here in the record.
15 And I'll draw everybody's attention, if I may, to page
16 35 of your pre-filed testimony. And I'm really looking
17 at -- there's a question that starts on line three, and
18 it says, "Please explain how the cost category for
19 'General and Administrative Costs' is affecting the
20 owners' costs forecast." You see that question, ma'am,
21 on line three?

22 A I do.

23 Q And here is your answer -- or, in part. You can read
24 all of it out loud, if you want, but the part that
25 intrigues me, I'm going to read -- "General and

1 administrative costs represent the direct support
2 provided to the NND team from non-NND cost centers
3 within SCE&G and SCANA. The original forecast for these
4 costs was based upon an estimated percentage of certain
5 owners' costs that was included in the 2006-2008 budget
6 projections." Do you see that?

7 A I do.

8 Q All right. So if I draw your attention back to Chart C,
9 I see where, in your original estimate your original --
10 let me be clear -- estimated percentage of some kind of
11 costs reflected a budget amount of \$22 million. You see
12 that?

13 A Uh-huh.

14 Q But yet, your estimated percentage was way off, wasn't
15 it?

16 A It depends on what it's a percentage of.

17 Q Well, that's my next question. What was it a percentage
18 of?

19 A I personally don't know what that is. I do know that it
20 was either AREVA, GE, or Westinghouse that gave them an
21 indication that a percentage of certain owners' costs
22 would be a good proxy as to what your administrative
23 support level would be. But, in fact, just like I've
24 indicated in discussions earlier, when we finally
25 decided on who had what responsibility of deliverables

1 under the EPC contract, we went back to the various
2 parties who had been charging our work order for the
3 previous two years and we gave them templates, basically
4 a blank sheet of paper, and asked them to fill out what
5 your labor resource was going to be on a yearly basis,
6 as well as your non-labor. When we tabulated that,
7 after going through what some people would characterize
8 as a painful exercise of being questioned as to why
9 their level of expenditure rose to the level that they
10 put on those templates, the summation of those templates
11 resulted in a 52 million -- or a -- yeah, a \$52 million
12 increase in G&A services, which are direct services for
13 the oversight of that project.

14 Q But if I understand your testimony today, Ms. Walker,
15 you're testifying that it was reasonable and prudent to
16 make an estimated percentage guess of what your costs
17 were, at least with respect to general and
18 administrative for the purpose of the Base Load Review
19 application.

20 A I mean, I don't think it was a guess. I think it was an
21 estimate. I think, as we've discussed I think two or
22 three times today, we sought input from a variety of
23 different sources, and having not been in the nuclear
24 construction business for 30 years, we did a high-level
25 estimate as to what those costs were going to be, with a

1 full understanding that we were presenting a
2 contingency. The Commission approved the contingency.
3 And our plan would be to go forward, just like we do
4 every single other very large project, and develop
5 refined, detailed cost-center budgets, and then we'd put
6 controls in place to be able to hold different cost
7 centers accountable for cost overruns or cost
8 underspends. And unfortunately, by order of the Supreme
9 Court, the contingency has been removed, and so in
10 keeping with the Supreme Court's order, we are coming
11 before the Commission for costs that we have now gone in
12 and itemized and identified as being incremental
13 increased costs over the original budget, and asking for
14 approval. And we consider these all to be appropriate,
15 necessary, and prudent for this project.

16 Q But again, as I understand your testimony, it was not
17 reasonable or prudent to ask your staff in May of 2008
18 what they estimated their costs would be, for the
19 purposes of your Base Load Review application. Is that
20 your testimony?

21 A I do not think it was reasonable for us to be able to go
22 and do that. I don't think that the general population
23 of SCANA would have enough insight into the deliverables
24 from the owner's perspective versus the consortium, to
25 be able to give you a very well educated, well thought-

1 out estimate as to what their contribution was going to
2 be to the project.

3 MR. ELLIOTT: Thank you so very much. No
4 further questions.

5 CHAIRMAN HOWARD: Let's take a break. We'll
6 see you at 4 o'clock

7 [WHEREUPON, a recess was taken from 3:45
8 to 4:00 p.m.]

9 CHAIRMAN HOWARD: Please be seated.
10 Commissioners. Any questions from the
11 Commissioners? Commissioner Wright.

12 EXAMINATION

13 BY VICE CHAIRMAN WRIGHT:

14 Q Hello.

15 A Hey.

16 Q Good afternoon to you. Ms. Walker, on the monitoring of
17 the NRC licensing activities, on page 33 of your
18 prefilled you talk about that, and what is the primary
19 cause of that increased time and effort to monitor? You
20 don't really refer to that.

21 A The primary cause? I think we've had extensive what
22 they call RAIs -- requests for additional information --
23 that have been pretty significant. And to date, the
24 Licensing Group answers a lot of those, but then they
25 also subcontract out Bechtel to try to develop those

1 responses, so that's been a pretty significant driver of
2 the increases.

3 Q Thank you. Earlier, when Mr. Byrne was up here, we
4 talked a little bit about NuStart and he gave a little
5 description of that. And you talk about it again in
6 your testimony, as well. Has the collaboration with
7 NuStart met, I guess, SCE&G's expectations?

8 A I think there probably has been some disappointment, in
9 that, you know, at one time you thought that there were
10 anywhere from five to six utilities that were going to
11 be collaborative and working together to get the license
12 for the Westinghouse AP1000. The level of commitment
13 and interest has diminished; we're not going to get the
14 \$6 million rebate from the plant that Mr. Byrne spoke
15 of, but likewise we're also having not quite the same
16 experience we were expecting out of the APOG, which is
17 the AP1000 Owners' Group. Again, you were going to be
18 looking at trying to take five utilities and
19 collaboratively identify and write anywhere from 3,000
20 to 4,000 policies and procedures that it takes to
21 operate the plant, and right now we only have two
22 utilities that are currently very committed to the
23 construction, and so the level of energy that is being
24 put into developing policies and procedures is somewhat
25 limited to SCE&G and Southern. And so the manager of

1 our Operational Readiness Group is already beginning to
2 have conversations with Southern to take that function
3 of all those policies and procedures -- take that
4 outside of the APOG entity, us developing it, because
5 that's going to be a significant commitment of resources
6 for us and Southern. And then, to the extent that
7 somebody comes in at a later date and wants to leverage
8 the work that we've done for two years, there will be a
9 cost associated with it, and at that point, maybe we'd
10 be able to get some money back for our ratepayers.

11 Q Well, you took away my question because I was going to
12 ask you where had it fallen short, and you've given me a
13 real good explanation, so I have no other questions.

14 A Okay. That's great.

15 CHAIRMAN HOWARD: Commissioners? Commissioner

16 Whitfield.

17 COMMISSIONER WHITFIELD: Thank you, Mr.

18 Chairman.

19 EXAMINATION

20 BY COMMISSIONER WHITFIELD:

21 Q Ms. Walker, on -- I believe it's page 41 of your
22 prefiled testimony, you discuss additional engineering,
23 testing, and documentation work to support nuclear
24 energy standards for the Unit 1 switchyard, and I
25 believe you might remember I asked Mr. Byrne about that

1 when he was on the stand. Work, of course, required to
2 integrate Unit 2 and Unit 3 output onto the grid.

3 A Uh-huh.

4 Q And, of course, that had to support the nuclear industry
5 standards with that work on the Unit 1 switchyard. Can
6 you think, or do you have some other examples of such
7 standards that you had to meet, that could not have been
8 anticipated earlier? Are there any other examples?

9 A Well, I mentioned the fatigue rule. That was pretty
10 significant. We knew that --

11 Q Right.

12 A -- that was actually anticipated when we signed the EPC
13 contract. The fatigue rule was in force, and I think it
14 was the spring of 2008, but we weren't certain at that
15 point if they were going to apply the fatigue rule to
16 the construction of nuclear, or if it was going to be
17 strictly the focus of operating plants. So it was
18 subsequent to our development of the BLRA filing that we
19 found out, in fact, it was going to be for construction
20 of the facility. So that was a pretty significant
21 change, because now, instead of having, I think it's
22 four shifts for security of the construction facility,
23 there will likely be a fifth shift added. So when you
24 start adding that fifth shift for the next eight years,
25 equipment and training, and then the labor and burdens

1 for carrying employees, that ends up being a pretty
2 significant dollar amount. But --

3 Q I think --

4 A -- other than -- pardon?

5 Q I think you had mentioned that fatigue rule --

6 A Yeah.

7 Q -- a little earlier.

8 A That, and the transmission, having to upgrade -- or, do
9 the transmission according to the nuclear standards
10 because it was connected to a nuclear plant. Those are
11 the two that come to mind for me. But again, you know,
12 I'm not a nuclear technical expert. Very much, finance
13 related.

14 COMMISSIONER WHITFIELD: Right, right. Well,
15 thank you. That's all I have, Mr. Chairman. Thank
16 you.

17 CHAIRMAN HOWARD: Commissioner Hall.

18 COMMISSIONER HALL: Thank you, Mr. Chairman.

19 EXAMINATION

20 BY COMMISSIONER HALL:

21 Q Good afternoon. I wanted to ask you about workers'
22 comp. I think 19 and 32 of your testimony, you
23 referenced owners' costs related to the workers' comp
24 insurance. Who is responsible for maintaining the
25 workers' comp coverage for -- I mean, are the

1 subcontractors responsible for their own, or how does
2 that work?
3 A We actually -- we made the election that we thought that
4 we could do a better job and get better pricing by
5 administering and operating that; we call it an OCIP, an
6 owner-controlled insurance program. So rather than Shaw
7 and Westinghouse having separate policies, and then
8 their subcontractors having their own policies, we're
9 going to have one workmen's comp policy that covers
10 anybody working at this site.

11 COMMISSIONER HALL: Okay, thank you.

12 CHAIRMAN HOWARD: Any other --

13 COMMISSIONER FLEMING: Yes.

14 CHAIRMAN HOWARD: Commissioner Fleming.

15 COMMISSIONER FLEMING: Mr. Chairman.

16 EXAMINATION

17 BY COMMISSIONER FLEMING:

18 Q In your testimony, you talked about Change Order No. 8,
19 and that you had -- that Westinghouse/Shaw had agreed to
20 forego escalation on \$69 million of the \$315 million of
21 the change order costs. How did you determine foregoing
22 escalation on the \$69 million, as opposed to the entire
23 \$315 million?

24 A Through the negotiations, one of the things we knew of
25 was there were two scopes of work, specifically, that

1 they were going to have a fixed contract, and that
2 related to the switchyard and the cooling towers. So,
3 as a result of our knowing that they had a fixed
4 contract with no escalation included in it, we told them
5 we weren't open to including additional amounts in those
6 scopes of work for those two -- cooling tower and
7 switchyard -- given that they weren't going to incur
8 anything, other than what they had fixed in their
9 contract. So we took escalation off the table for those
10 two scopes. And then for their safety program and what
11 they call their community outreach program, we felt
12 like, specifically, on the safety program, that we
13 didn't feel comfortable with escalation and we told them
14 we thought they could manage those costs so that they
15 didn't come in above the amount that was originally
16 built in the as-sold books, and so we told them simply
17 just to manage that program and not to exceed, you know,
18 the amount that they originally estimated based on 2007
19 dollars. So if that meant that they had to forego
20 certain, you know, celebrations for 500,000 man-hours
21 without a lost accident or they couldn't give away a
22 truck for some special incentive, then that's what they
23 needed to do, because we felt like there was ample money
24 in there, in 2007 dollars.

25 Q Okay. But you don't think it impacted safety issues,

1 per se?

2 A No, we don't.

3 Q So it was in the two areas that they didn't have any
4 escalation costs.

5 A They would not be subject to escalation, that's right,
6 because they were going to be -- they had fixed
7 contracts, so whatever they fixed those contracts at in
8 2007, which is the period when they signed and executed
9 those contracts, we gave them escalation for 2007 up to
10 the point in time when they fixed the contract, and that
11 was as much escalation as we would allow them. And so
12 we used the term "capped escalation," and it was capped
13 -- I think it was June of 2010 and maybe August of 2010
14 was the period that we capped it at.

15 Q And talk to me a little bit about community outreach.
16 What all does that involve?

17 A The vice president of the program -- of Shaw actually
18 indicated they were a little bit embarrassed that that
19 ended up being in the target arena. That typically is
20 in firm, because most customers aren't very interested
21 in paying or seeing community outreach, but it's a known
22 cost of being in a community that the Boy Scouts and,
23 you know, various other not-for-profit organizations are
24 going to come to large projects and ask for financial
25 support, whether it be to pay for a banner for the back

1 of the baseball field or to support some upgrade to a
2 camp. But when they did their cost buildup, it was, in
3 fact, in the target cost buildup, and in our inspection
4 when our team went up to Charlotte, probably one of 20
5 trips up there to review the as-sold books, they
6 demonstrated that, in fact, in the target cost was
7 community outreach. And so we were agreeable that it
8 was included. It's appropriate; it is a cost of doing
9 business. And so we agreed that they would, again, have
10 to manage that cost; we wouldn't give them escalation,
11 and they would be allowed to move that over into firm at
12 the same level that they had included it in their as-
13 sold books.

14 Q So, the ratepayers pay for the community outreach?

15 A Yes, and this -- it's not an advertisement function.
16 It's more of an expectation in the Jenkinsville/Chapin
17 area. There are going to be various not-for-profit
18 parties -- or -- parties, whether it be baseball teams or
19 Rotary clubs and things like that, that are doing
20 special events, and because they're going to be such a
21 significant presence in those communities, it's going to
22 be a cost to them, because they're going to be expected
23 to come to the table and make contributions. So
24 normally, you wouldn't see it. It would be just
25 embedded in the fixed price, and we would never talk

1 about it, but they know that that's a cost of doing
2 business on a project of a magnitude of building two
3 nuclear plants.

4 Q But that's a tax deduction for them, too, isn't it?

5 A It is a tax deduction for them, but it's not as long as
6 they pass it on to us, and they create revenue. So, you
7 know, it might be a cost that they incur, but then they
8 pass it on to us as revenue, so at that point they don't
9 get a tax deduction; we'll ultimately get the tax
10 deduction because 45 percent of that money will be
11 embedded into our cost through - in our rate base, and
12 as we depreciate and write that off, there's tax
13 implications, and so we will get the tax savings when we
14 write off Units 2 and 3, ultimately, when they're in
15 operation. So it actually ends up creating a revenue
16 stream for them, but we've neutralized it where they're
17 not necessarily going to have escalation, and so if they
18 wait and don't spend money until 2019, they're going to
19 get the benefit of whatever *Handy Whitman Index* adds to
20 that cost and then they can spend, instead of \$100,000
21 it would end up being \$250,000 that's at their
22 discretion. And we wanted to just minimize that. It
23 was a very small amount of money.

24 Q But it's essentially donations in the community?

25 A That's right.

1 Q Okay. And basically, the remainder that is escalated,
2 what does that go for?

3 A That actually follows the *Handy Whitman Index*.

4 Q I know, but I mean, exactly -- you were outlining what
5 the \$69 million covered, and the remainder is for the
6 units, per se?

7 A Well, that's actually different scopes of work. We had
8 the Site Design Engineering Group is going to be
9 escalated, because that's their labor. We moved that
10 over. The living allowance and relocation for their --
11 what we consider their professional staff, not the craft
12 personnel. That's been moved over, and it's subject to
13 escalation over the life of the project, since they're
14 going to be paying that out from 2011 through 2019.
15 Construction equipment is subject to escalation. The
16 heavy-lift derrick that we got at the price or the cost
17 of the two Lampson cranes is subject to escalation. And
18 probably the most -- the other most significant, or two,
19 would be office equipment and supplies, and their module
20 assembly building, and the on-site fabrication of the
21 modules that come from Louisiana.

22 Q Okay.

23 A Those are -- again, those are multiyear -- those will
24 span the project, so if we were to ask them to price
25 those based on today, and if we were to go into a really

1 high inflationary period, then say the period 2015
2 through 2019, you know, they may find it very difficult
3 or a challenge to be able to continue to manage and to
4 operate the construction site, given that we've capped
5 and limited their resources to be able to do the job.
6 So escalation is supposed to be a mechanism to make it
7 so that they're not guaranteed the escalation, but the
8 amount that they can bill based on their actual
9 experience has a higher-level cap. So maybe if it was
10 \$100, was going to be allowed for whatever it is, by the
11 time you get to 2015, maybe it's \$110. Well, if it's
12 \$108 to buy the item, it'd go up \$108, but they could
13 have spent up to \$110 without our disputing it.

14 Q All right, thank you.

15 A Uh-huh.

16 CHAIRMAN HOWARD: Commissioners?

17 [No response]

18 EXAMINATION

19 BY CHAIRMAN HOWARD:

20 Q Ms. Walker, how did you go about determining that
21 identifying and itemizing of \$174 million, referred to
22 at the bottom of page four of your testimony, what had
23 previously been covered by using part of the \$438
24 million in the owners' contingency fund, how did y'all
25 determine that?

1 **A** I mean, it's really just the difference between what we
2 presented to the Commission across the life of the
3 project versus when we did the zero-based budgeting and
4 gave everybody a blank sheet of paper and told them,
5 "For the end of 2010 through the end of -- or, the end
6 of 2018, and to the extent you still have work that
7 drives you into 2019, tell us what those costs are going
8 to be." We added them up and de-escalated those back to
9 2007 dollars, and it's just the differential between
10 owners' costs, as presented to you in the original BLRA,
11 and now this new summary of those de-escalated dollars,
12 and it comes up to \$145 million. And then the change
13 orders were another bucket of money that were de-
14 escalated back to 2007 dollars. And then -- there was
15 one other. The change orders, owners' costs, and the
16 transmission.

17 **CHAIRMAN HOWARD:** Okay. Thank you. Mr.
18 Zeigler, any redirect?

19 **MR. ZEIGLER:** No redirect.

20 **CHAIRMAN HOWARD:** Ms. Walker, you may step
21 down. Thank you, very much.

22 **WITNESS:** Thank you.

23 [WHEREUPON, the witness stood aside.]
24
25

1 proceeding that "...it wouldn't be practical to go out and
2 canvass across all of the different areas of SCANA to
3 try to get input into what they thought their level of
4 support was going to be for an EPC contract at the" same
5 "time when you were still trying to ferret out who had
6 what responsibility for the deliverables under the EPC
7 contract to develop those two units." Do you recall
8 testifying to that?

9 A It's in black-and-white here, so I'm certain I said it.

10 Q Yes, ma'am. You did. And I think, at my suggestion
11 that it might be helpful to have the costs before you
12 applied for the Base Load Review Act, you responded here
13 that I was trying to put the cart before the horse. Do
14 you recall that?

15 A That I said that you were trying to put the cart before
16 the horse?

17 Q Well, yes. I mean, if you read on, you'll see what you
18 testified to on line six was, "But also keep in mind
19 that, at the point in time when we were trying to
20 negotiate the contract, it wouldn't be practical..." and I
21 read that really long sentence. And so, in sort of
22 concluding your remark there, you said, "So you're kind
23 of trying to put the cart before the horse," by
24 ascertaining your costs before you come in for your Base
25 Load proceeding.

1 A And I would still be of that opinion.

2 Q Yes, ma'am.

3 A I think at that point, when they were trying to
4 negotiate the EPC contract, one of the sticking points
5 would be to determine who had responsibility to provide
6 what to the project.

7 Q Yes, ma'am. Thank you.

8 A So whether we were going to be building all of the
9 temporary structures that were going to be needed during
10 the course of the contract, versus it being part of the
11 EPC contract, that would drive a significant difference
12 in what you would consider owners' costs as compared to
13 the EPC contract costs.

14 Q We have page 304 of the transcript on the screen here,
15 from the 2010-376-E.

16 [Reference: 2010-376-E hearing transcript
17 at Page 304/Line 16 and following]

18 And I asked you this question, and I would ask you
19 if you recall the question and answer. "But, again, as
20 I understand your testimony, it was not reasonable or
21 prudent to ask your staff in May of 2008 what they
22 estimated their costs would be, for the purposes of your
23 Base Load Review application. Is that your testimony?"
24 And your answer was -- and I'll read part of it. You
25 may read all of it, if you wish -- "I do not think it

1 Q And you keep -- you're a very good manager, and you keep
2 a running tab of the costs, or the likely costs that you
3 think you may incur over and above what you filed for in
4 this proceeding, and you have some idea today of
5 additional costs that you might come back in here
6 another day -- next year -- and ask for, don't you?

7 A I keep a running tab. There are pluses and minuses in
8 there. And at this point, I would tell you that we do
9 not have incremental additional costs that would need to
10 be brought before this Commission.

11 We have continued to have monthly meetings -- and
12 they moved to every other month. We review in detail
13 variances, actual to budget; the functional area, both
14 within the NND team, as well as non-NND team. We've
15 identified timing differences, as far as when we were
16 expecting costs to be incurred versus when we think
17 they're now going to be incurred. We've found where we
18 have some savings that might be generated by a delay in
19 hiring somebody. But we've also found small items that
20 were costs that were not anticipated, and so those costs
21 offset each other. So the net, right now, is close to
22 being zero, with the exception of the timing of when
23 costs are going to actually hit the books and records of
24 SCANA.

25 Q All right. So, sitting here, the number is zero, but

1 there are some numbers that might hit the books and
2 records at SCANA, when, tomorrow? Or next week? I
3 don't understand your answer. Could you elaborate on
4 when those costs might hit the books of SCANA?

5 A In accounting terms, you know, you budget something --
6 and you can do this in your personal checking account.
7 You might expect to get an insurance bill in March of a
8 year, and for whatever reason, they send the bill in
9 April. Well, in March you may have budgeted for it, but
10 you didn't spend it. But you know it's going to come to
11 you in April, so that's not a savings. You can't go out
12 and make a major purchase because you didn't have to pay
13 your insurance, because you know your insurance is going
14 to come due in April. So, in March, it looks like
15 you're to the good and maybe could put money in savings,
16 based on whatever that premium is, but the reality is
17 you probably need to leave it in your checking account
18 because, in April, the bill is going to come in and
19 you're going to then disburse those funds.

20 So that's what we, in accounting, consider timing
21 differences. There's no permanent savings; it's just a
22 matter of when is the bill going to come in, as compared
23 to what period did you have it budgeted. And in a
24 project as large as the new nuclear project, with as
25 many cost centers, it would be expected to see

1 significant numbers of timing differences. And we track
2 and keep up with those.

3 Q Well, you've been in here every year under the Base Load
4 order. And last year, a bill came due to your
5 ratepayers of \$145 million in owner's costs, and this
6 year a bill has come due for \$131 million in owner's
7 costs. And so, on behalf of your ratepayers, I would
8 ask: When is the next bill going to come due, and what
9 do you estimate it will be?

10 A I can't -- just like everybody else has said in the
11 hearing, so far, I don't have a crystal ball. I know
12 that we are managing those costs. There is an edict at
13 the project to control costs. And those things that we
14 have got to have are things we're going to spend money
15 on. There are no luxury items built into our plans in
16 the future.

17 So at this point, I don't know of anything that
18 would indicate we'll be back in here, with the exception
19 of one particular change order that I think the ORS
20 staff and the NND staff are in disagreement. We believe
21 that we have identified and itemized the cost for a
22 particular change order that's titled cybersecurity. We
23 have a budgetary estimate. We're in the throes of
24 trying to execute a change order for that amount. Those
25 costs are going to be incurred. The regulatory changes

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1 have been made at the NRC that we've got to comply with.
2 But, for whatever reason, ORS is not comfortable that we
3 have enough detail to be able to substantiate that those
4 are known and measurable and should be included in the
5 budget. I have a different opinion. I think those
6 costs are going to be incurred.

7 Those costs, if we have -- if the 4.9 that we've
8 got in the filing that we have today ends up being
9 slightly over, those amounts that are over would never
10 be expended; they would never hit the work order and the
11 ratepayers would never pay those amounts. So all of our
12 expenses are -- whether their budgetary estimates are
13 high or low, the only thing that we put into revised
14 rates are actual costs that are incurred in the project,
15 based on disbursements.

16 Q So the good news for your ratepayers is that, perhaps
17 other than \$5 million of cybersecurity, you may not be
18 in here again for additional costs.

19 A That could be the case. And that would be ideal for the
20 company. We don't look to try to bring added cost to
21 the project.

22 Q Would you disagree with me that it would be ideal for
23 your customers, too?

24 A Absolutely.

25 Q Now, let me draw your attention to your testimony on

1 page 14 of your prefiled testimony in this docket,
2 please.

3 A [Indicating.]

4 Q And you testify in support of the additional \$28-\$29
5 million in IT cost? Do you see that?

6 A I do.

7 Q In 2008, when SCE&G applied for its Base Load Review
8 order, was it not apparent to the company that it would
9 have to upgrade its IT budget for licenses, software,
10 and hardware, and implementation costs?

11 A I would suggest to you that, back in 2008, that the
12 budgetary estimate, which was a product of input from
13 the industry, the APOG members, Westinghouse, perhaps
14 even AREVA and other nuclear technology, was not at a
15 granular level where you identified IT and IT
16 implications. What we found last year in the hearing
17 was that we had distributed cost-center templates and
18 asked them to fill out what they expected their costs
19 were going to be through the life of the project, and
20 the assumption at that point was that each of those
21 functional areas would include in their cost-center
22 budget any IT costs that they would expect, to be able
23 to support their function in the operating plant.

24 Unfortunately, a lot of our managers made the
25 assumption that the software and the infrastructure that

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1 was currently being used in the operation of Unit 1 was
2 going to be able to be transported and used, as is, in
3 Units 2 and 3. The project made the decision to bring
4 in a director from our Information Technology group out
5 of our Corporate group, for him to be able to go in and
6 canvass and do an inventory of all of the IT
7 infrastructure, all of the IT systems that Unit 1 was
8 currently using, and make an assessment as to whether or
9 not those products required additional licensing to be
10 able to own and operate those systems, and also to
11 decide whether or not they were multiunit-capable. We
12 wouldn't want the maintenance records for Units 2 and 3
13 and Unit 1 to be co-mingled; those need to be separated
14 so that we can understand what we've done with each of
15 those units.

16 So what we did was, we did what we call an IT
17 roadmap, which was a multi-month function where we had
18 an IT team assembled; they worked with each of the
19 functional groups over at Unit 1 to determine what
20 systems were in operation, and then they did the
21 research to figure out what would need to be done to
22 make it so that those systems could support Units 1, 2,
23 and 3, without our breaching any kind of contract with
24 the owner to those systems.

25 Q And when did you do that IT -- make -- draw that IT

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1 roadmap, ma'am?

2 A That would've been probably in the last 10, 11 months.

3 Q All right. Since the last order, in --

4 A Absolutely.

5 Q -- May of -- you didn't do it in 2008, did you?

6 A No.

7 Q All right. And just moving through your testimony as
8 quickly as you will permit me, you're here in support of
9 an additional \$7.8 million in facility needs; is that
10 correct?

11 A That's right.

12 Q And you knew, when you designed -- when you entered your
13 EPC contract and came before this Commission in 2008,
14 that you had additional facilities needs, did you not?

15 A Again, in 2008, they were not in granular detail. But
16 in our previous filing, we did come in and we talked
17 about some of the facilities. We talked specifically
18 about cost increases as it related to the new operating
19 building for the administrative personnel. We talked
20 about the extension that needed to be added to the
21 nuclear learning center, and how the simulators were
22 training Unit 2 personnel.

23 What we have found, though, as Mr. Lavigne has
24 testified to, with the increased staff, and then the
25 compression of the construction project for Units 2 and

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1 3 -- we advanced 2 out by nine months, but we've also
2 advanced Unit 3 back seven and a half months, so, by
3 virtue of there being a more compressed construction
4 schedule, some of the facilities that we were expecting
5 to be able to begin using, some of the temporary
6 construction facilities, are not going to be available
7 to us. So what we are running up against is having
8 adequate spacing for the employees, to be able to bring
9 them in and allow them to have office space to do the
10 procedure writing, the training, and the planning in the
11 operation -- planning for the operations of the units.
12 So a vast majority of this increase is office space,
13 primarily temporary, to be able to house personnel until
14 we're able to go operational with Unit 2.

15 Q But your 2008 estimate that you brought before this
16 Commission left out this particular item, here.

17 A I wouldn't say it left it out. I mean, that was a
18 composite budget, or estimate, and to say what was in it
19 and what was not in it, I don't think is a fair
20 characterization of what that composite estimate was
21 made up of. So I would disagree that it wasn't in
22 there. It was probably included in there, but also,
23 every utility uses differing facilities and differing
24 software. And we've had to look at our particular needs
25 based on our three-unit site, and try to come up with

1 the best solution to be able to serve a multiunit site.

2 And at this point, just for clarification, those
3 projects or those operating systems, as well as any IT
4 infrastructure upgrades that are made that service Units
5 1, 2, and 3, only those costs that are applicable to
6 Units 2 and 3 are going to be capitalized in this work
7 order and rolled into revised rates. We went system-by-
8 system and made a determination as to who is the
9 beneficiary of that system. And to the extent that Unit
10 1 is a one-third participant and they gain one-third of
11 the benefit of that system, a third of those costs --
12 both the purchase and implementation costs -- will go
13 directly to Unit 1, and will not go into revised rates
14 through the BLRA.

15 Q The cybersecurity issue you mentioned, how much is the
16 request in this docket?

17 A I think it's \$4.950 million.

18 Q And what is the ORS position?

19 A The ORS position right now is, is that we don't have
20 enough detail in support of that budgetary estimate.

21 Q And --

22 A Their preference would be for us to wait to get
23 additional information from the consortium.

24 Q And in light of the ORS position, what is SCE&G's
25 position?

1 A We're not opposed to that. My concern is that, if we
2 leave this open and we don't incorporate it in this
3 particular order, then it's assured that we will, in
4 fact, have to come back before the Commission with that
5 change order and get approval to add that to the budget.

6 Q Well, in connection with that, you do talk a little bit
7 about spare parts, in your testimony. Do you recall
8 that?

9 A I do.

10 Q And apparently there are going to be some spare parts
11 that we're going to be asked to pay for. Is that a
12 correct understanding of your testimony?

13 A Spare parts are going to be a cost to the project, and
14 those would be recoverable through the BLRA.

15 Q And so you know you're coming back for the spare parts,
16 anyway, don't you?

17 A I do not. The testimony here was just to try to raise
18 awareness that the spare parts inventory has not been --
19 we've not had the opportunity to assess it. The
20 consortium owes us a list of what they consider the
21 mandatory spare parts that they would expect us to have
22 on hand, to support their being able to do the startup
23 in the six-month period that they've got scheduled.
24 We've not yet gotten that. We should get it in the next
25 12 months. My expectation is that that will go through

1 a negotiation process. They're probably going to --
2 they're going to have a laundry list that may be beyond
3 what we think is necessary, and so we will negotiate to
4 what we consider to be an appropriate level of mandatory
5 spare parts. We will also look to see that long-lead
6 materials are adequately addressed through an inventory
7 process. And we anticipate trying to work with
8 Southern, to be able to leverage our units being close
9 in proximity, using the exact same equipment, and try to
10 minimize the number of pieces and parts that both of the
11 plants would have on-site, but instead try to come to
12 something where it supports both with less units.

13 Q I thought I recalled something in your EPC contract that
14 provided they were supposed to -- the consortium was
15 already supposed to have given you the spare-parts
16 information.

17 A The spare-parts inventory is supposed to have been
18 delivered -- I think it was within 180 days of -- I'm
19 not sure what the cutoff was on that. It might've been
20 receipt of COL. They've not produced that.

21 Q That was in your EPC, right?

22 A [Nodding head.]

23 Q And you had the EPC in hand when you filed in May of
24 '08, so what dollar value did you put on spare parts in
25 your 2008 application?

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1 A In our owners' costs, we have \$15 million. That a 100
2 percent number. I think that equates to slightly under
3 \$9 million for SCE&G, and then embedded in the EPC
4 contract there is also an additional \$15 million, which
5 is a 100 percent number, so if you took that to an SCE&G
6 level, that would be slightly over \$9 million.

7 Q So you've got \$9 million in your Base Load order now,
8 right?

9 A No, actually we have 18. The EPC contract is in here,
10 as well as the owners' costs.

11 Q And they have not complied with their contract in
12 providing you that within 90 days of your COL?

13 A Not at this time.

14 Q Any penalty for that?

15 A No.

16 Q Not other than perhaps to the ratepayers, right?

17 A I don't see where there would be a penalty. We're not
18 going to be ordering spare parts today, and if we did,
19 we wouldn't be paying for them. And only until we've
20 actually made payment on something does the ratepayer
21 begin to start paying on that. So there's no penalty
22 whatsoever to the ratepayer by us delaying that
23 inventory purchase.

24 MR. ELLIOTT: No further questions. Thank
25 you.

Fleming.

EXAMINATION

BY COMMISSIONER FLEMING:

Q Good afternoon.

A Good afternoon.

Q I wanted to -- first of all, I wanted to ask you what is the total cost of the project to date, that you have spent?

A What was actually spent inception to date?

Q Yeah, up to date.

A Inception to date, through March of 2012 -- in the way of the EPC contract and owner's costs, is \$1,373,948,000. And then in addition to that, AFUDC has been accrued on those amounts, and that's \$48,044.

Q Okay. And --

A Of that -- that's forty- -- yeah, that's right. So the \$1,373,000,000 represents 27 percent of what we have filed today as being the projected cost of the project.

Q Okay.

A In 2007 dollars.

Q Okay. In 2007 dollars.

A Right.

Q And could you just calculate it in today's dollars?

A In 2012 dollars?

Q Uh-huh?

1 clarity in what all is involved in that \$137.5 million
2 that we've been talking a lot about. What all goes into
3 that?

4 A The Change Order 16 that we had covered earlier? I
5 mean, I'll just go back in history just a little bit.
6 The consortium came to us and put forth a claim saying
7 that they were entitled to a change order, and there
8 were --

9 MS. GREENLAW: I'm sorry. I cannot hear. And
10 I know it's --

11 WITNESS: I'm sorry.

12 MS. GREENLAW: I apologize.

13 WITNESS: I can scoot up. But anyway, the
14 consortium came to the owner with a claim saying
15 that they were due, by virtue of entitlement, a
16 change order for the change in the shield building
17 design, the structural module redesign, the COLA
18 delay -- the impact the COLA delay had on the
19 project -- and then lastly they presented a claim
20 because of additional work that was going to be
21 created by the crevices that were in the granite in
22 Unit 2's foundation.

23 Their claim -- when they presented the claim,
24 they had a pretty sizable dollar value. What we
25 did, as a project, was we assembled a team. The

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1 consortium had a team, and the owner had a team.
2 And what we did was we went into detail and tried
3 to understand what and how they made calculations
4 as far as the impact to them. We also went forth
5 and provided our senior executives what we
6 considered to be an entitlement paper on each of
7 those topics, to explain what we thought resulted
8 in entitlement or why we didn't think that they
9 were entitled for each one of those claims. The
10 consortium did the same thing.

11 At the end of the day, we made recommendations
12 to our senior executives, who finally met with
13 their senior executives, and through a negotiation
14 and a pooling of all of those four elements into
15 one subject or one change order, to try to come to
16 a consensus that would allow for a reasonable cost
17 and for us to be able to progress in the project
18 without going into litigation or arbitration, they
19 were able to negotiate what we consider to be a
20 fair and reasonable settlement.

21 We acknowledge that there was some entitlement
22 to the consortium as it related to the shield
23 building, not very much entitlement when it came to
24 structural module redesign that they were required
25 to do. We had settled on a COLA delay that we

1 thought had been mitigated significantly by
2 changing Unit 3 and advancing it by seven and a
3 half months. And when you sum those up, you came
4 up with 137.5.

5 **BY COMMISSIONER FLEMING:**

6 **Q** Okay. So the dollar amount, then, is the settlement for
7 the shield and the delay and the rock?

8 **A** The shield building, the structural module redesign, the
9 rock that was unexpected. You know, we didn't deny --

10 **Q** The rock with the cavities, huh?

11 **A** Yes. And we didn't deny that they were entitled to a
12 change order on that, because they had not expected to
13 see that; we didn't expect to see that. They didn't
14 create that -- I think it created -- I think it was a
15 30-day schedule impact, because they had to fill those
16 crevices in with concrete, and then you had to allow
17 maybe 17-inch lifts; you had to cure, then put another
18 17 inches on it. So, you know, we acknowledged there
19 was a schedule impact because of the rock that was at
20 our site, so they were entitled to a change order in
21 that. But again, they didn't really -- the executives
22 didn't negotiate on an item-by-item basis. They pooled
23 it. They understood in some cases there was some
24 entitlement, but in other cases there was little to no
25 entitlement, and at the end of the day they struck a

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1 negotiated settlement of the 137.5.

2 Q So that the project could continue?

3 A Continue.

4 Q All right, good. The last time -- I think it was the
5 last time; there've been two times before -- we had some
6 discussion about some community support and outreach
7 that was being done?

8 A Right.

9 Q And I believe the agreement was that that would not --
10 even at that time -- that the customer would not be
11 responsible for that?

12 A Right. And we took action after the order -- we
13 actually took that out of the work order, and we charged
14 that to what we consider our below-the-line account
15 distribution in that period for the entire amount, which
16 is a cost that's borne by our shareholders only. So
17 it's not in the work order, it's not embedded in revised
18 rates, nor will it ever be.

19 Q Okay. So you're --

20 A I think the amount was 103 --

21 Q -- continuing to do that; you're just handling it --

22 A Right.

23 Q -- through the shareholders?

24 A Right. We credited the work order \$103,000, I think was
25 the amount. So even if the charges come through on the

1 invoices, there's a credit in the work order that
2 offsets it, where we took it below the line and our
3 shareholders bore that cost.

4 Q Yeah, and I believe I saw that listed on one of the
5 sheets.

6 A Yeah, you probably -- because we'll continue to have to
7 explain that, because that's the difference between the
8 EPC contract and what we were allowed under the EPC
9 contract as far as an approved budget for it.

10 Q Okay. And going back to the Shaw thing, the LA -- or,
11 Lake Charles and Shaw, I had asked the question earlier
12 about, with the addition of quality assurance personnel
13 that had to be added on --

14 A Right.

15 Q -- I guess, including all the other endeavors you've
16 gone through to try to bring the equipment up to what it
17 is expected to be --

18 A Right.

19 Q -- what kind of expense has that added? Do you have a
20 dollar amount of what that is costing SCE&G, to bring
21 the quality of the shield up to where it should be for
22 the project?

23 A I mean, I have a very different view of that. And the
24 way I see it, and my understanding of the project --
25 granted I'm not nuclear nor am I an engineer; I'm an

1 accountant. But I've been on the budget for three years
2 and been in a lot of meetings -- some contentious and
3 some professional. But anyway, the discussion, you
4 know, --

5 Q That's probably on Shaw's side. SCE&G never loses their
6 cool.

7 A We don't. We really don't.

8 [Laughter]

9 We've seen them get pretty emotional with us. But
10 anyway, as far as the QA function, you know, granted, we
11 are adding QA people to our project team, from an
12 oversight perspective, but I think that the QA add that
13 we are making is in direct response to the NRC clearly
14 sending us a signal that the expectation is that, as the
15 owner and the licensee, our QA ultimately is responsible
16 for the quality of the product, and then of the safety-
17 related components that go into that plant. And so, I
18 think that, from an oversight perspective, we needed to
19 be able to demonstrate to the NRC that we are doing the
20 appropriate level of oversight. And, with less than the
21 staff has proposed today, I think it would be hard for
22 the NRC to sign off on our project and the licensee
23 having done the right level of oversight, given some of
24 the QA issues or challenges that industry has had.

25 So, I mean, I understand, you know, where some

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1 people could rest on, "Well, this is a direct cost or a
2 cost to the project because of SMS, or Doosan, or
3 Mangiarotti," but the reality is, I think that we have a
4 duty to the NRC to have people on-board representing the
5 owner, to be able to say that we're doing the oversight
6 that's required, given the heightened level of oversight
7 and Q&A that the consortium is having to do. So, the
8 consortium is adding QA to their personnel and to these
9 various sites. They've got -- a term I've learned in
10 the three years I've been on the project -- they've got
11 boots on the floor in each and every one of the major
12 manufacturers that have been challenged with QA and
13 schedule issues.

14 Q Okay. So you don't have a dollar figure, then, for
15 that?

16 A No, because I don't know how you would measure how much
17 of the QA is appropriate as the licensee, versus what's
18 the appropriate level of QC or QA that's incremental
19 just because of some of the issues we found in the
20 industry.

21 Q But you have had to add additional personnel to check
22 for quality assurance at this particular place.

23 A I think that, and other locations. I think that the QA
24 personnel have been stretched thin initially on the
25 project, and as we have continued to run into QA

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1 challenges, we've seen the need to have more visibility
2 at the various shops, not just at SMS. There are quite
3 a few trips to go to Mangiarotti, Doosan -- you know,
4 all the different major manufacturers for the safety-
5 related equipment have faced challenges throughout the
6 first three or four years of the project.

7 Q So you think the number was underestimated to begin
8 with?

9 A I think we underestimated the learning curve that we
10 were going to be facing in the new nuclear renaissance,
11 and having the fabrication of all of those major pieces
12 of equipment meet the QA standards of the nuclear
13 industry.

14 Q Okay. And I know that -- I believe -- you all discussed
15 the IT a bit earlier?

16 A Right.

17 Q And I wanted to just go into that a little bit more. I
18 guess what I would like a better understanding: I
19 believe you -- the way it was in your testimony was that
20 you felt like you were going to be able to build on the
21 infrastructure that was there, but that infrastructure
22 was installed in 1984? Is that correct?

23 A Right.

24 Q I'm just wondering what the thought process was, on why
25 you could assume that that same technology could be

1 adapted for a newer use, as quickly as technology --

2 A Has been changing?

3 Q -- is changing. I mean, it changes from week to week,
4 almost.

5 A Yeah, I understand. The last filing that we did, we
6 actually did the budget revision and added the dollars
7 that we needed to be able to add the infrastructure that
8 was needed --

9 Q Well, I guess I'm going back, and maybe that -- I know
10 it was before you were there, but I'm just wondering
11 what the initial thought process was.

12 A Well, I think that goes back to where we didn't have a
13 granular budget. You know, we used data points that we
14 had gotten from Westinghouse, as far as what they
15 thought owners' costs would run; you know, the APOG, the
16 five utilities that were to participate in APOG; I think
17 that they saw that input from GE, because GE had a
18 technology that they were trying to sell. So I think
19 when they sought that insight into owners' costs from
20 those various parties, there wasn't a detailed budget.
21 You know, your IT infrastructure, your IT systems, you
22 know, they were fairly generic in doing that budget.

23 So it wasn't until after I got to the project that
24 we started doing a deeper dive. I was able to add staff
25 to the project team and bring on finance people that

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1 could go in and work directly with non-accounting but
2 very technical managers and help them to come to terms
3 with, "What are the pieces and parts of costs that
4 you're going to be incurring through the life of this
5 project?"

6 And, you know, the initial -- the initial product
7 they produced, we had embedded in there the assumption
8 that all of the various functional groups would include
9 in their budget any software needs that they might have.
10 And that's where the mistake came up, in that they
11 assumed that whatever the Unit 1 system was -- not
12 necessarily infrastructure, because the infrastructure
13 would be dealt with separately, but the various systems,
14 like they've got a system by name of CHAMPS, and it's
15 their work management tool. All of their work products,
16 their time entry, their inventory -- there's a whole
17 host of different aspects of the project that are
18 tracked on CHAMPS. Well, nobody put CHAMPS in their
19 budget, because they all assumed that CHAMPS would be
20 able to simply just be replicated and used over at Units
21 2 and 3, when the reality is, we have a contract with
22 CHAMPS that doesn't allow us to just simply replicate it
23 and use it in any facility we have, nor does CHAMPS
24 allow you to have three separate, distinct nuclear
25 plants so that you can see the inventory for Unit 1

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1 separate from Unit 2, separate from Unit 3.

2 So when we started -- that was probably the
3 beginning of our trying to figure out how are we going
4 to deal with IT. And I met with the executive over our
5 Information Technology at Corporate, and we proposed
6 that we would have one of the -- I think one of the
7 strongest directors he's got, to come to the nuclear
8 project, with the sole focus of trying to gain an
9 understanding and develop an inventory of every system
10 that we have, that's used at Unit 1, and make good
11 business decisions as to whether or not we needed to
12 replicate it and go back and get the additional licenses
13 to be able to use it, or to see if we could get it
14 upgraded so that it could accommodate multiple units at
15 one singular site.

16 And so when we finished doing that, I mean, we
17 literally have a laundry list of various systems --
18 CHAMPS being one of them -- where we know that's the
19 CHAMPS system that we're currently implementing. We
20 have an implementation plan, we have implementation
21 costs, and we are tracking those, as we speak, as costs
22 are incurred, so that we can hit the milestones as to
23 when those various pieces and parts need to be in
24 production to support NND, and then ultimately it will
25 be used at Unit 1 -- because it will be on a different

- 1 platform, so they'll be upgrading their CHAMPS system.
- 2 Q So will SCANA continue to be the one kind of heading up
3 this particular part?
- 4 A Absolutely. But that -- I mean, SCANA has got the IT --
5 Information Technology -- organization that has got a
6 lot of expertise. And rather than trying to duplicate
7 that expertise at the site, either at Unit 1 or at the
8 project, it makes economic sense to leverage the
9 technology and the expertise that we have in our
10 Corporate IT function. So we've tasked and brought
11 people out of the Corporate Information Technology
12 Department, and they are now a part of the NND project
13 team, with a focus solely on all of the IT
14 implementations.
- 15 Q Okay. And so, as we talked about before, it's changing
16 rapidly?
- 17 A Right.
- 18 Q So, do you anticipate that any future adjustments that
19 need to be made, that you're now -- that you have the
20 structure in place now, that you can make those
21 adjustments as it evolves?
- 22 A As far as the information technology?
- 23 Q Uh-huh?
- 24 A I think that we do.
- 25 Q Okay.

1 A You know, our -- one of the things that we will be
2 diligent in doing is holding the project teams, through
3 all of these different implementations, accountable, to
4 explain to us, you know, where they are in their budget
5 for each of those projects. I mean, to the extent
6 they're under- or over-budget, what are you going to do
7 to bring them back in line?

8 So the same level of accountability for owners'
9 costs will be imposed on the IT team, to be able to meet
10 the budget that we presented to you all today. I can't
11 make any commitment that there won't be one or two of
12 those projects that might not go over. Hopefully, there
13 will be one or two that might come under, and the net
14 will still end up being the same \$28 million that we
15 presented today. But, IT projects are known for being a
16 struggle to implement. I think most companies struggle
17 with--

18 Q We're struggling --

19 A Yeah.

20 Q -- all this new technology.

21 A Yeah, they're hard, and we understand that there's a lot
22 of dynamics to it. But I think we've got a very
23 effective technical group that should help to make that
24 a success.

25 Q And what about the cybersecurity? Is that a part of

1 this particular group?

2 A No, the cybersecurity is solely a Westinghouse/Shaw
3 element. That's a change order they proposed. And that
4 cybersecurity came out of regulation from the NRC. And
5 what they did was, we broke it up into two phases.
6 Rather than them give us an estimate that didn't have a
7 lot of intelligence embedded into the estimate, we broke
8 it up into two phases. Phase 1 was basically a payment
9 for them to go out and do the research, to figure out
10 what all components that are being manufactured perhaps
11 in the United States or perhaps overseas needed to have
12 modifications made so that the firewalls or, you know,
13 whatever the other technical term is that will protect
14 the system, that might be embedded in that equipment, is
15 strong enough to avoid cyberattacks. So in Phase 1, the
16 goal was to go identify, you know, what pieces of
17 equipment required retrofitting because they were
18 already well beyond the stage of putting that technology
19 into the equipment, or what piece of equipment was still
20 yet to be fabricated and needed to have design
21 modifications to incorporate the cyber-requirements.

22 And so we're at the stage now where they have done
23 that research, if you will, and now we're in the midst
24 of developing and defining what the scope of Phase 2 is
25 going to be. And with that intelligence, also, we'll be

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1 able to identify what the budget -- what they expect the
2 change order to cost.

3 And at this point, we do have a budgetary estimate.
4 I was talking to one of my associates today; we're
5 expecting a proposed draft -- or, a draft change order
6 probably within the next three to six weeks. The
7 \$4,950,000 that we have today in our filing is
8 definitely subject to change. That's not -- we don't
9 have a change order that is near execution, that's got
10 that dollar amount in it, so the \$4,950,000 may not be
11 the exact number, so we may end up having to come back
12 even if you approve that today. Next year, we might
13 come back and say, "Well, the \$4,950,000 ended up being
14 \$5,500,000." Or it might come out to be \$4,500,000. So
15 I don't have anything concrete that I can point to --

16 Q But you've got about 1.8 in the budget now, right?

17 A I think it's 4.9.

18 Q Well, I thought there was additional money for
19 cybersecurity.

20 A Well, the 1.8 was Phase 1.

21 Q Okay.

22 A And that's where they were going to do the research to
23 figure out, "Okay, where does the cybersecurity
24 regulation impact the equipment, and where in the --
25 what stage of fabrication is that equipment in?"

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1 Q Okay.

2 A So now they're -- Phase 2 is --

3 Q This is actually implementing it?

4 A Right. -- is to go in and fix the equipment so it meets
5 the cyber-requirements. So that is very much a
6 budgetary estimate.

7 Q So, but you are -- the IT Department is working on
8 cyberissues?

9 A It would be the IT Department of the consortium. Our IT
10 personnel within SCANA would not be involved with that.

11 Q Oh, I don't mean that.

12 A Yeah.

13 Q I mean, the IT -- the part that we talked about earlier
14 that --

15 A Right.

16 Q -- would need -- certainly, I would anticipate -- to be
17 cybersecure, as well.

18 A Right.

19 Q As much as you can be.

20 A [Nodding head.]

21 COMMISSIONER FLEMING: Okay. All right. I
22 think that's it for me. Thank you.

23 CHAIRMAN WRIGHT: Commissioners. Anyone else?

24 [No response]

25 Any redirect?

1 **MR. GISSENDANNER:** We have no redirect of Ms.
2 Walker and we'd ask that she be excused.

3 **CHAIRMAN WRIGHT:** You may be excused.

4 **WITNESS:** Thank you.

5 [WHEREUPON, the witness was excused.]

6 **CHAIRMAN WRIGHT:** Mr. Zeigler.

7 **MR. ZEIGLER:** We would call Dr. Joseph Lynch.

8 [Witness sworn]

9 THEREUPON came,

10 **J O S E P H M . L Y N C H , P h . D . . ,**
11 called as a witness on behalf of the Petitioner, South
12 Carolina Electric & Gas Company, who, having been first duly
13 sworn, was examined and testified as follows:

14 **DIRECT EXAMINATION**

15 **BY MR. ZEIGLER:**

16 **Q** Please state your name for the record.

17 **A** Joseph Lynch.

18 **Q** And by whom are you employed, and in what capacity?

19 **A** SCANA Corporation, and I'm the manager of Resource
20 Planning.

21 **Q** Dr. Lynch, have you prepared or had prepared under your
22 supervision certain written testimony of 17 pages that
23 has been prefiled in this docket?

24 **A** Yes, I have.

25 **Q** Are there any corrections to that testimony?

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1 A No.

2 Q If I were to ask you the questions that are contained
3 there today, would your answers be the same?

4 A Yes, they would.

5 MR. ZEIGLER: Mr. Chairman, I would move to
6 have Mr. Lynch's testimony entered into the record
7 as if given orally from the stand.

8 CHAIRMAN WRIGHT: Yeah, we will -- Dr. Lynch's
9 testimony will be read into the record as if given
10 orally from the stand.

11 [See pgs 895-911]

12 BY MR. ZEIGLER:

13 Q And Dr. Lynch, as filed, were there three exhibits to
14 your testimony?

15 A Yes.

16 MR. ZEIGLER: Mr. Chairman, we would ask that
17 the exhibits be entered into the record also.

18 CHAIRMAN WRIGHT: Dr. Lynch's -- both of them?
19 JML-1 through -3?

20 MR. ZEIGLER: -1 through -3, yes.

21 CHAIRMAN WRIGHT: All right. It will be
22 entered into the evidence of the case.

23 BY MR. ZEIGLER:

24 Q And, Dr. Lynch, have you subsequently prepared a fourth
25 exhibit which has been served on the parties, which is

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1 JML-4?

2 **A** Yes, that's correct.

3 **Q** And I believe we've had a copy that has been given to
4 the court reporter that includes some corrections in
5 typos and the like, that have also been distributed to
6 the parties. Is that the current exhibit?

7 **A** Yes.

8 **MR. ZEIGLER:** Mr. Chairman, we would move that
9 that subsequent Exhibit JML-4 be entered into the
10 record.

11 **MR. GUILD:** Mr. Chairman, may I be heard,
12 please?

13 **CHAIRMAN WRIGHT:** Yes.

14 **MR. GUILD:** Mr. Chairman, this document,
15 JML-4, is late-filed. It was served on the parties
16 on September 27th electronically, late in the
17 afternoon, and hand-delivered at that time, as
18 well. I would point out that the Commission's most
19 recent revised prefiling directive called for all
20 rebuttal testimony by the company, including
21 exhibits, to be filed with the Commission and
22 served on the parties by August 23, 2012, not
23 September 27; that, thereafter, my client, the
24 Sierra Club, had an opportunity, as we chose to
25 exercise, to file surrebuttal testimony that we

1 timely filed on September 6. Counsel for SCE&G
2 served this JML-4, which is entitled "Comparative
3 Economic Analysis of Completing Nuclear
4 Construction or Pursuing a Gas Resource Strategy,"
5 dated September 27, 2012, JML-4, again, Thursday
6 afternoon.

7 On Friday afternoon, I -- after
8 consulting with Dr. Cooper, our expert -- I served
9 a data request on the company. That data request,
10 thanks to counsel, was promptly responded to, and I
11 got a telephone-book-thick stack of data late
12 Sunday evening. My friend Belton Zeigler and I,
13 both in shorts -- or in casual clothes -- exchanged
14 pleasantries on my front porch late Sunday evening.
15 I know he had a long weekend.

16 Short and long of it, Mr. Chairman and
17 members of the Commission, is, this document is
18 late-filed and is a very substantial and
19 significant piece of work that I think deserves to
20 be discussed by the Commission.

21 Under the circumstances, given Dr. Cooper's
22 presence, I have no objection to this document
23 being received in evidence, so long as Dr. Cooper
24 is thereafter free to supplement his surrebuttal
25 testimony, to fairly address the materials that are

1 included in Dr. Lynch's proposed Supplemental
2 Exhibit JML-4. So the short and long of it is, on
3 the condition that Dr. Cooper is free to supplement
4 his testimony when he takes the stand next, I have
5 no objection to Dr. Lynch's supplemental exhibit
6 coming in under these circumstances.

7 CHAIRMAN WRIGHT: To clean this up for me, I'm
8 going to break this up, okay? First, before I
9 address -4, I'm going to go ahead and we will admit
10 JML-1 through -3 as Exhibit No. 8, into the
11 evidence of the case.

12 [WHEREUPON, Hearing Exhibit No. 8 was
13 marked and received in evidence.]

14 And then we are going to rule that we will
15 allow what you're asking for. We're going to admit
16 the Exhibit JML-4 as Exhibit No. 9. And he's going
17 to be prepared -- I mean, permitted to go on the
18 stand to address it; you can do whatever you feel.

19 [WHEREUPON, Hearing Exhibit No. 9 was
20 marked and received in evidence.]

21 MR. GUILD: Thank you, Mr. Chairman.
22 Appreciate it.

23 MR. ZEIGLER: Very good. So the ruling of the
24 Chair is that Dr. Cooper will be allowed to respond
25 from the stand to the material that's being

1 presented?

2 CHAIRMAN WRIGHT: Yes, sir.

3 BY MR. ZEIGLER:

4 Q Dr. Lynch, have you prepared a summary of your
5 testimony?

6 A Yes.

7 Q Would you please present that to the Commission and the
8 parties?

9 A Good morning, Mr. Chairman and members of the
10 Commission. My testimony points out certain problems
11 with the positions asserted by the Sierra Club through
12 the testimony of its witness, Dr. Cooper. My testimony
13 shows that, even assuming low natural-gas prices in the
14 future, nuclear is still the superior option.

15 From a pure cost basis, SCE&G's investment to date
16 makes going forward with the units a superior strategy,
17 compared to switching to gas. The units also have a
18 lower total cost now, which is due to lower-than-
19 expected escalation since 2008. This lower cost
20 contributes to the advantage that nuclear has over gas.

21 But cost studies aside, I would reiterate that
22 base-load planning decisions should not be made on a
23 one-dimensional cost analysis. This is particularly the
24 case when the analysis has been based on very low prices
25 for one fuel -- in this case, gas -- based on the recent

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1 change in market conditions.

2 Dr. Cooper argues that SCE&G should abandon the
3 construction of the nuclear units because natural-gas
4 prices have decreased, as shown by forecasts from the
5 Energy Information Administration, EIA. But EIA
6 forecasts of future gas prices change on a regular
7 basis. Exhibit JML-2 shows the portion of the EIA's own
8 error analysis of its natural-gas-price projections that
9 compares forecast to actual results. There are errors
10 in every cell in this table. EIA reports sizable errors
11 even in its short-term predictions. EIA recognizes that
12 its gas-price forecasts are almost always wrong; it is
13 only a question of how wrong.

14 Another indication of the uncertainty of gas-price
15 forecasts is the confidence interval that the EIA
16 publishes for its projection of short-range prices.
17 Based on the 95 percent confidence interval that EIA has
18 published, prices in December 2013 could be as high as
19 \$7.76 per million BTU or as low as \$2.11 per million
20 BTU. The mean forecast price is \$3.63. The upper bound
21 of EIA's confidence interval is 214 percent greater than
22 the mean forecast, while the lower bound is only 42
23 percent lower than the mean. This means that EIA
24 believes that there's an equal probability of prices
25 being 214 percent higher than forecasted as there is of

1 prices being 42 percent lower. EIA believes that the
2 risk of higher prices is much greater than the risk of
3 lower prices.

4 As a practical observation, EIA did not anticipate
5 the recent drop in natural-gas prices, as a result of
6 tracking technology. I would expect the same would be
7 true going forward. EIA would not be likely to be able
8 to predict how other factors -- like errors in its
9 current reserve calculations, future pipeline
10 constraints, new environmental limitations on fracking,
11 or changes in demand for gas -- might affect prices.
12 For reasons such as these, utility planners do not put
13 much confidence in projections of natural-gas prices
14 when conducting base-load studies. That is why
15 sensitivity analyses are important.

16 In my testimony, I identify two factors that could
17 tend to increase natural-gas prices. First, domestic
18 natural-gas prices are out of alignment with the cost of
19 energy internationally. They are also not in alignment
20 with the cost of other energy sources in the United
21 States. Low prices are increasing the demand for
22 natural gas as it displaces other generation fuels, such
23 as coal. This will place upward pressure on the price.
24 There are good reasons to believe that low domestic gas
25 prices may not remain in place indefinitely.

1 Second, environmental regulations may push natural-
2 gas prices higher still. New EPA air emissions
3 regulations are forcing the early retirement of older
4 coal generating plants, including SCE&G's. Recent
5 regulatory changes have taken coal out of consideration
6 as a fuel for new plants to meet future electric demand.
7 Increased reliance on natural gas, as an electric
8 generation fuel, will increase the demand for natural
9 gas dramatically. Current pipeline resources are a long
10 way from being able to meet the increased demand.

11 Of course, burning gas as fuel also emits carbon.
12 There is the additional risk that CO₂ emissions costs or
13 regulations will be imposed on gas, as the use of coal
14 as a generation fuel is suppressed. As CO₂ limits
15 ratchet up, gas is the next logical target.

16 Environmental concerns over fracking as a
17 production technique could also lead to increases in the
18 price of natural gas.

19 Although none of these outcomes are certain, they
20 indicate that there are forces present today that could
21 cause a forecast of future low gas prices to disappear.
22 it is for reasons such as these that SCE&G seeks to
23 build the generation systems that can perform well in a
24 range of price and supply conditions. We do not rely
25 too heavily on gas-price forecasts at any one point in

1 time.

2 Even accepting Dr. Cooper's approach to planning
3 and gas-price assumptions, completion of the
4 construction of the units is still the most prudent
5 economic decision for the company. Since the original
6 economic studies were run, two principal changes have
7 occurred that make a material difference in the cost of
8 the nuclear generation strategy. First, the projected
9 cost of nuclear construction is \$551 million lower than
10 the original 2008 forecast. Based upon the levelized
11 carrying costs of investing in nuclear generation, this
12 decrease alone resulted in an \$88 million reduction in
13 the levelized cost of nuclear generation per year, over
14 the 40-year planning horizon for the study.

15 Furthermore, for planning purposes, it is only the
16 costs that are left to be spent that are relevant to
17 deciding whether to complete construction of the
18 facility. As the Petition in this proceeding shows, by
19 the end of the year, only about \$3.8 billion of the
20 costs for the units will remain to be spent. Taking a
21 conservative position that 75 percent of the costs
22 remain to be spent -- the true number is closer to 67
23 percent -- then the levelized cost of the nuclear
24 generation scenario should be further reduced by \$230
25 million. In sum, the levelized cost of the nuclear

1 generation strategy in 2008 should be reduced by a total
2 of \$318 million.

3 The cost advantage of the nuclear strategy goes
4 higher still when you consider the cost SCE&G would
5 incur in canceling the construction of the units to
6 pursue a gas strategy. These costs would also need to
7 be factored into the analysis to make it complete.

8 Taken together, these factors show a reduction in
9 the cost of the nuclear strategy that outweighs the
10 effect of the change in gas cost. It outweighs any
11 other factor that might reasonably be anticipated to
12 change. I would also note that I have much more
13 confidence in the cost and pricing that lead to the \$318
14 million adjustment, in favor of nuclear, than in the
15 other numbers. The \$318 million is based on real
16 contracts and cost forecasts. Dr. Cooper's \$115 million
17 adjustment could disappear entirely if EIA revises its
18 gas-price forecast in the future. I also agree that Dr.
19 Cooper's assertion that the Commission cannot ignore --
20 I also agree with Dr. Cooper's assertion that the
21 Commission cannot ignore the carbon issue. Rulings by
22 the EPA and the US Supreme Court will likely result in
23 the imposition of carbon-emissions costs in the form of
24 taxes, cap-and-trade mechanisms, or mandatory capture-
25 and-sequestration requirements. For the purpose of our

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1 studies, the form that costs take are not important; the
2 costs themselves, however, are likely to be significant
3 and would increase the advantage nuclear has over gas.

4 Dr. Cooper mentions a savings of \$4-\$8 billion
5 associated with his analysis, but he does not specify
6 how he arrived at this calculation. I assume that the
7 numbers are the product of annual average levelized
8 savings of \$115-\$200 million multiplied by 40 years. If
9 so, this approach to aggregating values would not be
10 used in the utility planning context. Rather, in the
11 planning context, the present value would be computed.
12 The present value of a \$2-million-a-year reduction in
13 annual costs over 40 years, at SCE&G's cost of capital,
14 is \$2.4 billion. The present value for \$115 million
15 reduction in levelized costs would be \$1.4 billion. The
16 \$4-\$8 billion reported by Dr. Cooper is far too high.
17 Using the same approach, the present value of the \$318
18 million in levelized cost savings represented by the
19 nuclear generation strategy today is \$3.9 billion.
20 Continuing construction of the units is more economical
21 than abandoning them and pursuing a natural-gas
22 strategy, by a wide margin.

23 In response to Dr. Cooper's surrebuttal testimony,
24 I performed the study he testified needed to be done.
25 The study computed the economics of completing the

1 nuclear units versus abandoning them and constructing
2 combined-cycle gas units instead. The study used
3 current gas forecasts that were lower than those used by
4 Dr. Cooper. It used updated costs for capital costs and
5 other relevant parameters. The study was based on the
6 same modeling and technique used in the 2008 studies.
7 Multiple sensitivity analyses were run. The study shows
8 that the best assessment of the advantage of completing
9 nuclear, versus switching to gas, is \$290 million per
10 year, levelized over 40 years. The study also confirms
11 that the gas-resource strategy creates a system that is
12 very sensitive to volatility in gas prices or CO₂ costs.
13 Under the gas-resource strategy, customers will pay much
14 higher rates as future gas prices or CO₂ costs trend
15 toward the higher end of the reasonably foreseeable
16 range.

17 For all these reasons, it is my professional
18 judgment that, as a planning matter, Dr. Cooper's
19 testimony does not demonstrate that switching to a gas
20 strategy should be given serious consideration as an
21 alternative to completing the units. This completes my
22 summary.

23 MR. ZEIGLER: Thank you.

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REBUTTAL TESTIMONY

OF

JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2012-203-E

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Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Joseph M. Lynch and I am Manager of Resource Planning for South Carolina Electric & Gas Company ("SCE&G" or the "Company").

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York, with a Bachelor of Science degree in mathematics. From the University of South Carolina, I received a Master of Arts degree in mathematics, an MBA and a Ph.D. in management science and finance. I was employed by SCE&G as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and in 1991, I was promoted to my current position of Manager of Resource Planning.

1 Q. WHAT ARE YOUR CURRENT DUTIES AS MANAGER OF RESOURCE
2 PLANNING?

3 A. As Manager of Resource Planning I am responsible for producing
4 SCE&G's forecast of energy, peak demand and revenue; for developing the
5 Company's generation expansion plans; and for overseeing the Company's load
6 research program.

7 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE
8 COMMISSION?

9 A. I have, on a number of occasions.

10 Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS
11 PROCEEDING?

12 A. My testimony points out certain problems with the positions asserted by the
13 Sierra Club through the testimony of its witness Dr. Cooper. Specifically, I
14 support Mr. Marsh's testimony that points out the problems in the analytical
15 approach that Dr. Cooper uses. I provide further support for Mr. Marsh's
16 conclusion that natural gas prices are highly volatile, and that our knowledge of
17 future natural gas prices is too limited and uncertain to allow a utility to rely on a
18 single forecast of future prices in planning for future base load generation
19 capacity. All other considerations aside, I also show that because of the
20 investment that SCE&G has made to date in the V. C. Summer Nuclear Units 2
21 and 3 (the "Units"), going forward with construction of them is clearly superior
22 from a pure cost basis even assuming low natural gas prices.

1 Q. DO YOU AGREE WITH MR. MARSH'S ASSESSMENT OF THE FLAWS
2 IN DR. COOPER'S ANALYSIS?

3 A. I agree that Dr. Cooper's analysis is flawed for many reasons. Most
4 importantly, he looks only at one set of data as to future gas costs. This is not how
5 utility planning decisions are made. Mr. Marsh's testimony explains this very
6 well.

7 Q. IN HIS DIRECT TESTIMONY DR. COOPER ARGUES THAT THE
8 "COLLAPSE OF GAS PRICES HAS BEEN DRAMATIC" AND THAT
9 THE EIA IS CURRENTLY PROJECTING NATURAL GAS PRICES TO
10 BE 62% LESS THAN SCE&G'S BASELINE PROJECTIONS IN THE 2008
11 CASE. SHOULD SCE&G ABANDON CONSTRUCTION OF ITS
12 NUCLEAR UNITS BECAUSE OF THIS?

13 A. Of course not. The natural gas markets experience a great deal of volatility
14 in prices and planners see as much or more volatility in the projections of future
15 natural gas prices. In Exhibit No. __ (JML-1), I show a graph of EIA's current
16 natural gas price projections using data contained in their Annual Energy Outlook
17 ("AEO") 2012 forecast as well as that contained in their AEO 2009 forecast. The
18 2012 forecast is about 60% or so less than their 2009 forecast. So three years ago
19 the EIA did not foresee that a dramatic collapse in natural gas prices coming. By
20 the same token, EIA may not be able to foresee a dramatic reversal in prices in
21 another three years if that were coming.

1 **Q. DO YOU PUT MUCH CONFIDENCE IN THE EIA'S NATURAL GAS**
2 **PRICE PROJECTIONS?**

3 **A.** Planners, if they are prudent, do not put much confidence in anyone's
4 projection of natural gas prices. That is why almost all resource planning studies
5 involve scenario planning and sensitivity analysis around the most uncertain
6 drivers of cost. The price of fossil fuels is one of the most volatile and uncertain
7 drivers of energy costs. Each year the EIA publishes an analysis of the accuracy
8 of its natural gas price forecast. Exhibit No. __ (JML-2) shows a portion of EIA's
9 error analysis of its natural gas price projections, which shows the percent error in
10 their past forecasts. An important thing to notice in the table is that most entries
11 show sizable errors even in short term predictions and there is no entry with a 0%
12 error. This means that the EIA's forecast is almost always wrong. It is only a
13 question of how wrong.

14 **Q. DOES THE EIA PROVIDE SOME INDICATION OF THE**
15 **UNCERTAINTY SURROUNDING ITS NATURAL GAS PROJECTIONS?**

16 **A.** It does. The error analysis I just discussed provides one indication of
17 uncertainty. Another is a confidence interval that the EIA publishes with respect to
18 its projection of short-range prices. In Exhibit No. __ (JML-3), I show an EIA
19 chart containing a 95% confidence interval that EIA has computed around its
20 forecast of gas prices through 2013. This chart suggests the possibility of prices in
21 December 2013 reaching as high as \$7.76 per MMBTU and as low as \$2.11 with

1 an expected price of \$3.63. Clearly the EIA sees much uncertainty in its forecasts
2 of gas prices even in the next two years.

3 **Q. IS THE UNCERTAINTY IN NATURAL GAS PRICES BALANCED, THAT**
4 **IS, IS THE RISK OF HIGHER PRICES JUST AS GREAT AS THE RISK**
5 **OF LOWER PRICES?**

6 **A.** No, the risk of higher prices is much greater than the risk of lower prices.
7 Common sense and economics would suggest that natural gas producers would not
8 produce and sell gas at a loss, at least not for very long, so there is a floor on how
9 low gas prices can go. On the other hand, experience tells us that, if there is a
10 ceiling, it is fairly high. The unbalanced nature of price risk for natural gas can be
11 demonstrated in EIA's confidence interval I just discussed. The upper bound of
12 the 95% confidence interval is 214% greater than the mean forecast while the
13 lower bound is 42% lower. This means that there is an equal probability of prices
14 being 214% higher as there is of them being 42% lower than the expected price.
15 Clearly the upside risk is greater.

16 **Q. ARE THERE ECONOMIC FORCES THAT WOULD TEND TO PUSH**
17 **NATURAL GAS PRICES HIGHER?**

18 **A.** Yes. There are two categories of factors that come to mind: supply and
19 demand forces and environmental regulations. As to supply and demand, natural
20 gas prices are low now because of an abundance of supply being provided by the
21 new production technology of hydraulic fracturing, or fracking. Because of the
22 low prices, the demand for natural gas is increasing and this will put upward

1 pressure on the price. For example, natural gas generation is displacing a high
 2 percentage of coal generation in the day-to-day dispatch of generating systems
 3 throughout the country. This will tend to push the cost of gas generation toward
 4 the cost of coal generation, which in today's market is higher. In the longer term,
 5 there are gas exporters seeking authority to build liquefaction capacity to sell
 6 domestically produced natural gas in the international market.¹ Today, U.S. prices
 7 for natural gas are much lower than prices internationally.² If export sales
 8 increase, this will increase demand for domestically produced natural gas. A high
 9 level of exports would link domestic prices more closely to the global energy
 10 market and global prices. Furthermore, low gas prices in the United States are
 11 leading to expansion in gas-intensive industries like petrochemicals,
 12 pharmaceuticals and other businesses that use gas as a chemical feedstock or
 13 energy source.³

14 As to environmental regulations, the effect of environmental regulations
 15 will take at least two forms. Recently promulgated EPA air emissions regulations,
 16 such as those Mr. Byrne discusses, are forcing the early retirement of coal capacity
 17 which cannot economically be scrubbed. Given the cost of carbon sequestration,
 18 newly issued CO₂ regulations have taken new coal generation off the table as a

¹ Project sponsors are seeking Federal approval to export domestic natural gas" April 24, 2012, <http://www.eia.gov/todayinenergy/detail.cfm?id=5970/>.

² Id.

³ Accenture, North America Flexes its Manufacturing Muscle, http://www.accenture.com/us-en/outlook/Pages/outlook-journal-2012-north-america-flexes-industrial-muscle.aspx?c=mc_myoutlook3-_10000009&n=emc_0712

1 means for meeting future electric demand. Electric utilities will be meeting much
2 of their future capacity needs through the addition of new gas fired generation.
3 This will increase the demand for natural gas and put still more upward pressure
4 on gas prices. Increasing reliance of natural gas as a fuel for electric generation
5 will also create the need for new pipeline capacity to deliver gas in the required
6 volumes, which involves construction and permitting costs and risks, which can
7 lead to higher costs. Of course, if you burn gas, you emit carbon, so another risk of
8 gas generation is the risk that CO₂ costs will be imposed directly on gas as a fuel.

9 The other form of regulation deals with the technique of fracking. There is
10 concern in the environmental community that the technique is harmful to the
11 environment and requires more regulation. Such regulations would increase the
12 cost of producing natural gas and as a result would also increase the price of gas in
13 the market. How these developments will progress is uncertain, but they indicate
14 that there are forces at work in the economy that could cause today's forecasts of
15 future gas prices to prove inaccurate.

16 **Q. WHY DO YOU SAY THAT COAL IS "OFF THE TABLE" FOR**
17 **ELECTRIC GENERATION TODAY?**

18 **A.** On May 27, 2012, the Environmental Protection Agency issued new
19 regulations based on a finding that CO₂ should be regulated as an air pollutant.
20 The new regulations require all new or refurbished electric generation facilities to
21 meet CO₂ discharge limits which are based on the expected emissions from a
22 combined-cycle natural gas generation unit. This means that given current state of

1 carbon sequestration technology, new coal generation or refurbished coal plants
2 are not likely to be permitted for operation in the United States. Apart from
3 nuclear generation, there is now only one type of dispatchable base
4 load/intermediate load generation resource that can be built in most of the United
5 States. That is combined-cycle gas generation.

6 **Q. DR. COOPER ESTIMATES THAT THE LOW GAS PRICES**
7 **CURRENTLY PROJECTED BY THE EIA IMPLIES A \$115 MILLION**
8 **REDUCTION IN THE LEVELIZED COST OF A NATURAL GAS FIRED**
9 **GENERATION STRATEGY AND THAT SCE&G SHOULD THEREFORE**
10 **ABANDON THE CONSTRUCTION OF ITS NUCLEAR UNITS FOR**
11 **ECONOMIC REASONS. DO YOU AGREE?**

12 **A.** Absolutely not. I have demonstrated that there is a great deal of uncertainty
13 in natural gas prices and in their projection. Prudent resource planning decisions
14 cannot be made based on a single scenario of natural gas price projections. I have
15 also shown that the likelihood of higher gas prices is much greater than that of
16 likelihood of lower gas prices. Therefore, there is a greater likelihood that the
17 \$115 million advantage that Dr. Cooper calculates will decrease or disappear than
18 that this advantage will get larger.

19 **Q. FOR THE SAKE OF ARGUMENT ASSUME THAT SCE&G PUTS ASIDE**
20 **THE PRUDENT PRACTICE OF USING SCENARIO PLANNING AND**
21 **SENSITIVITY ANALYSIS IN RESOURCE PLANNING STUDIES AND**
22 **ACCEPTS DR. COOPER'S APPROACH OF USING ONE SCENARIO OF**

1 **LOW GAS PRICES OVER 40 YEARS TO MAKE PLANNING**
2 **DECISIONS. WOULD YOU AGREE BASED ON THE RESULTING**
3 **ECONOMICS THAT SCE&G SHOULD ABANDON ITS NUCLEAR**
4 **CONSTRUCTION AND BUILD NATURAL GAS FIRED GENERATION?**

5 A. Absolutely not. Assuming that natural gas prices will be low for the next 40
6 years and further assuming that Dr. Cooper is correct in his calculation that this
7 results in a \$115 million reduction in the levelized cost of a natural gas generation
8 strategy, you still need to look at those important drivers of cost that have changed
9 related to the nuclear generation strategy going forward.

10 Q. **PLEASE EXPLAIN.**

11 A. At least two changes have occurred since the original studies were run that
12 would make a material difference in the cost of the nuclear strategy. One relates to
13 the cost of the Units. In his direct testimony Mr. Byrne notes that the projected
14 cost of the nuclear construction is about 8.7% or \$551 million lower than the
15 forecasts on which the original studies were run. Over a 40-year period, the
16 levelized carrying cost of investing in nuclear generation is 16%. This means that
17 on a levelized basis, every dollar invested in the Units equates to \$0.16 per year in
18 capital related costs on average during the 40-year period. This levelized carrying
19 cost includes all the costs of carrying the nuclear investment, including
20 depreciation, taxes, insurance, interest and so forth. Using a 16% levelized
21 carrying charge for nuclear investments, and applying it to the \$551 million
22 reduction in the cost of the Units we are now forecasting, we can compute the

1 difference that this reduction in cost makes to the levelized cost of the nuclear
2 generation strategy. The result is that because of the \$551 million reduction in the
3 construction cost forecast, the levelized cost of nuclear generation is reduced by
4 about \$88 million ($\$551 \text{ million} * 0.16\%$) per year over the 40 year planning
5 horizon for the study.

6 Furthermore it is well recognized in utility planning practice that when
7 making decisions about investments going forward, it is only the going-forward
8 costs that are relevant. These are the costs that are left to be spent. If the question
9 is whether or not SCE&G should complete the nuclear Units, only the cost of
10 completing the Units is relevant.

11 In Exhibit 1 of her testimony, Ms. Walker reports that about 25% of the
12 construction costs for the Units have already been spent and 75% remain to be
13 spent to complete the project. This means that the levelized cost of the nuclear
14 generation scenario should be reduced by \$230 million ($\$5,762 \text{ million} * 0.16 * 0.25$), where \$5,762 million is the current cost of the Units, 25% is the amount that
15 has been spent and 16% is the levelized carrying cost of nuclear investment. Thus
16 to update the 2008 study to current conditions, the levelized cost of the nuclear
17 generation strategy should be reduced by a total of \$318 million to reflect the fact
18 that the cost of the Units has declined by \$551 million and only 75% of that lower
19 cost remains to be spent.
20

1 Q. WHAT ABOUT THE ADDITIONAL COSTS THAT SCE&G MIGHT
2 HAVE TO PAY TO ITS CONTRACTORS AND OTHERS TO ABANDON
3 THE UNITS AT THIS TIME?

4 A. As Mr. Byrne discusses, SCE&G would have to pay additional costs to its
5 contractors and others to abandon construction of the Units and switch to a gas
6 strategy. Those costs have not been quantified. But at this point in the project,
7 incurring them would be a necessary part of moving to a gas strategy. Because
8 these costs are not included in my analysis, it understates the advantages that the
9 nuclear strategy has over gas to that extent. But this would only cause the
10 advantage of nuclear strategy to go up. The cost of abandonment would increase
11 the value of continuing with nuclear construction compared to switching to a gas
12 strategy.

13 Q. WHAT THEN IS YOUR CONCLUSION BASED ON THE UPDATED
14 ECONOMICS?

15 A. The economics clearly demonstrate that the nuclear construction should
16 continue. Given current capital cost forecasts and the value of investment to date,
17 the levelized cost of the nuclear generation strategy is reduced by \$318 million.
18 Even if the levelized cost of the gas generation strategy is reduced by \$115 million
19 as Dr. Cooper suggests, the nuclear strategy maintains its economic advantage by
20 a wide margin.

21 Q. WHICH ADJUSTMENT DO YOU CONSIDER THE MOST RELIABLE --
22 DR. COOPER'S ADJUSTMENT OF \$115 MILLION BASED ON AN

1 ASSUMPTION OF LOW GAS PRICES OVER THE NEXT 40 YEARS OR
2 THE \$318 MILLION ADJUSTMENT BASED ON THE NUCLEAR
3 CONSTRUCTION COSTS?

4 A. I have much more confidence in the \$318 million adjustment than the \$115
5 million. More than two-thirds of the cost left to be spent under the EPC contract
6 are fixed or subject to fixed escalation rates. Of course the 25% of the cost of the
7 Units that has already been spent is fully known and measurable. On the other
8 hand, I have already discussed the volatility and uncertainty of prices in the natural
9 gas market. The \$115 million adjustment to the natural gas generation strategy is
10 based on an assumption of low gas prices over the next 40 years which is very
11 uncertain. All indications are that the uncertainty of the gas price forecast is much
12 greater than the uncertainty surrounding the cost of completing the construction
13 cost of the Units.

14 Q. DR. COOPER TESTIFIES THAT THE COST OF THE NATURAL GAS
15 GENERATION STRATEGY COULD BE REDUCED BY AS MUCH AS
16 \$200 MILLION IF A ZERO COST FOR CO₂ EMISSIONS IS ASSUMED IN
17 ADDITION TO LOW NATURAL GAS PRICES. HAVE YOU
18 CONSIDERED THIS IN YOUR ANALYSIS?

19 A. In its 2008 studies, SCE&G had assumed in its base case scenario a cost of
20 \$15 per ton of CO₂ emitted which gave the nuclear strategy an \$88 million
21 advantage over the natural gas generation strategy in levelized costs.

1 Dr. Cooper testifies at one point that if a zero cost per CO₂ ton is assumed,
2 then the \$87 million could be added to the \$115 million discussed above thereby
3 producing a \$200 million reduction in levelized costs for the natural gas
4 generation strategy. However, Dr. Cooper subsequently testifies that the
5 Commission cannot "ignore the carbon issue" so I assumed that his discussion
6 about a \$200 million reduction was meant more as commentary than serious
7 economic analysis.

8 **Q. CAN THE COMMISSION IGNORE THE CARBON ISSUE?**

9 **A.** I agree with Dr. Cooper that the Commission cannot ignore the carbon
10 issue. The EPA has ruled that CO₂ emissions endanger human health, and the U.S.
11 Supreme Court has ruled that under the Clean Air Act if the EPA makes such an
12 endangerment finding, then it must regulate CO₂ emissions. Carbon emission
13 cost, by the way, can come as taxes, cap and trade mechanisms, or mandatory
14 capture and sequestration requirements. Each of these approaches imposes costs.
15 For purpose of our studies, what form these costs takes is not particularly
16 important.

17 **Q. ASSUME FOR ARGUMENT SAKE THAT THE EPA REVERSES ITS**
18 **ENDANGERMENT FINDING AND THAT THE COST OF CO₂ EMISSION**
19 **IS ZERO IN THE FUTURE AND ASSUME FURTHER THE NATURAL**
20 **GAS PRICES STAY LOW OVER THE NEXT 40 YEARS AND**
21 **CONSEQUENTLY THAT THE NATURAL GAS GENERATION**
22 **STRATEGY IS \$200 MILLION LESS RELATIVE TO THE NUCLEAR**

**STRATEGY IN LEVELIZED COSTS. BASED ON ECONOMICS SHOULD
SCE&G ABANDON THE NUCLEAR CONSTRUCTION AND BUILD GAS
FIRED PLANTS UNDER THESE ASSUMPTIONS?**

A. Absolutely not. First I should repeat that important resource planning decisions should be based on thorough studies using scenario planning and sensitivity analysis. All that Dr. Cooper's analysis demonstrates is that scenarios can be imagined in which gas might be more economical than nuclear. Even accepting Dr. Cooper's approach, which I cannot do, SCE&G should not abandon the nuclear construction because, as already discussed, updated information on construction costs show at least a \$318 million reduction in the cost of the nuclear strategy based on where we stand today. Even when compared to the \$200 million reduction for the natural gas strategy which Dr. Cooper puts forward, and which even he does not seem to fully accept, the economic advantage of the nuclear strategy remains.

**Q. DR. COOPER MENTIONS A SAVINGS OF \$4 BILLION AND POSSIBLY
AS MUCH AS \$8 BILLION ASSOCIATED WITH HIS ANALYSIS. WHAT
DO THESE NUMBERS REPRESENT AND HOW DO THEY RELATE TO
THE LEVELIZED COSTS THAT YOU HAVE BEEN DISCUSSING?**

A. While Dr. Cooper does not specify how he made his calculation, it seems that his \$8 billion number was calculated as the product of 40 years times the annual average levelized savings of \$200 million. He makes a similar calculation based on his \$115 million levelized savings assertion, and calculates a \$4 billion

1 savings. This is not how this calculation would be made in the planning context.

2 The approach that would be used in the planning context would be to compute a
3 present value which is a standard calculation used in economic analysis to
4 determine the accumulated present value of a future revenue stream.

5 **Q. PLEASE EXPLAIN.**

6 **A.** The accumulated present worth of a future revenue stream gives you the
7 value today of a stream of payments or savings going out into the future. The
8 calculation uses a present value factor that is typically calculated using the cost of
9 capital for the entity in question. Using a weighted cost of capital of 8.7%, which
10 is SCE&G's actual weighted average cost of capital as of December 31, 2011, the
11 accumulated present value factor for a 40-year levelized stream of dollars is 12.05.
12 Thus the accumulated present value for the \$200 million levelized stream is \$2.4
13 billion ($12.05 \times \$200$ million) not \$8 billion. A similar calculation can be made for
14 Dr. Cooper's levelized savings calculation of \$115 million. In this case the
15 accumulated present value is \$1.4 billion ($12.05 \times \$115$ million) as opposed to the
16 \$4 billion reported by Dr. Cooper.

17 **Q. HOW WOULD YOUR NUMBERS REFLECTING INCREASED SAVINGS FOR**
18 **THE NUCLEAR STRATEGY COMPARE ON A PRESENT VALUE BASIS?**

19 **A.** I computed an increase in the levelized savings for the nuclear strategy of
20 \$318 million resulting from the reduced capital costs of completing the nuclear
21 Units. The present value of this amount over the planning horizon is \$3.9 billion,
22 which compares to the present value of Dr. Cooper's asserted savings for the gas

strategy (\$115 million levelized with \$15 CO₂ costs) of \$1.4 billion. Even accepting Dr. Cooper's assumptions as to future gas prices, the cost reduction he computes in the gas strategy is less than half the saving in the nuclear strategy. Compared to \$200 million in levelized savings that Dr. Cooper computed, which he admits improperly assumes no CO₂ costs, the results are \$2.4 billion in savings for the gas strategy compared to \$3.9 billion in savings for the nuclear strategy. Even assuming no CO₂ costs, nuclear savings are still over 60% greater than the savings for gas. Clearly, at this point in the project continuing construction of the nuclear Units is more economical by a very wide margin than abandoning them and pursuing a natural gas strategy. The comparisons are set out in the Chart A, below.

Chart A

Dr. Cooper's Adjustments to Natural Gas Strategy Costs (reduced costs, in millions)		SCE&G's Adjustments to Nuclear Strategy Costs (reduced costs, in millions)	
<u>Low Gas Cost</u>		<u>Going-Forward Cost</u>¹	
Levelized Per Year	\$115	Levelized Per Year	\$318
Accumulated	\$4,000	Accumulated	- ²
Present Value	\$1,400	Present Value	\$3,900
<u>Low Gas Cost & No CO₂ Cost</u>			
Levelized Per Year	\$200		
Accumulated	\$8,000		
Present Value	\$2,400		

¹ Reflecting reduced construction cost of \$551 million and the fact that 25% of the reduced cost of the project has already been spent.

² Not computed.

1 **Q. DOES SCE&G SEE AN ADVANTAGE TO ITS NUCLEAR GENERATION**
2 **STRATEGY THAT GOES BEYOND THE ECONOMIC ISSUES**
3 **BROUGHT UP BY DR. COOPER AND ADDRESSED IN YOUR**
4 **TESTIMONY?**

5 **A.**Yes, it does. Under its nuclear strategy SCE&G will achieve a balanced
6 mix of capacity. In 2019 SCE&G will have 31% nuclear generation, 28% natural
7 gas and 27% coal. This puts SCE&G in a good position to protect its customers
8 and mitigate the cost impacts from the volatility of fossil fuel prices and the
9 uncertainty of future environmental regulations on fossil fuels.

10 **Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

11 **A.**Yes, it does.

1 MR. ZEIGLER: Dr. Lynch is available for
2 cross-examination and questions by the Commission.

3 CHAIRMAN WRIGHT: Thank you. Mr. Guild.

4 MR. GUILD: Thank you, Mr. Chairman.

5 CROSS EXAMINATION

6 BY MR. GUILD:

7 Q Good afternoon, Dr. Lynch. How are you?

8 A Good afternoon, Mr. Guild.

9 Q Dr. Lynch, were you around when Mr. Marsh testified
10 earlier?

11 A Yes.

12 Q All right. And Mr. Marsh related that, up until this
13 case, the company had not performed a review of the
14 prudence of continuing construction of the plant, and to
15 paraphrase him, he explained that because no material
16 changes had come to his attention that would warrant
17 such a change, but, that upon receiving Dr. Cooper's
18 surrebuttal testimony, he directed you to undertake the
19 comparative analysis which is the document that is in
20 evidence now is JML-4. Is that correct?

21 A Yes, that's correct.

22 Q And when did Mr. Marsh direct you to undertake such a
23 comparative analysis, Dr. Lynch?

24 A We began the study -- it was a week ago, this past
25 Friday.

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1 Q And the time flies, but Thursday was when I got it, the
2 27th of --

3 A So the Friday before that.

4 Q Okay, the Friday before that.

5 A Yeah.

6 Q All right.

7 A But it was a long week, and the nights.

8 Q Indeed it was. And a long weekend, as well.

9 A Yes.

10 [Laughter]

11 Q But when did Mr. Marsh, if he did, when did he direct
12 you to undertake the study? Was it at that point?

13 A It was actually the Monday, where we had a collaboration
14 whether to complete it, or not. I had begun it on
15 Friday, making the runs -- runs that go overnight to
16 make a lot of the calculations -- and Monday we sat down
17 together and came to a decision that we needed to
18 complete the report.

19 Q All right. So I don't have my calendar in front of me,
20 but if Thursday was the 27th -- that's the date of the
21 document, the date I got it -- it was the Friday
22 preceding that that you undertook the runs, you just
23 said, correct?

24 A Correct.

25 Q The Monday thereafter, the Monday before last Thursday,

1 you decided to complete it, and the rest is history.

2 Right?

3 **A** Yes.

4 **Q** Okay, thank you. Now, then, thereafter, on Friday I
5 prepared, with Dr. Cooper's help, a series of data
6 requests and got them to Mr. Burgess, Mr. Zeigler, and
7 they were kind enough to get them to me late Sunday
8 evening. But I take it that Mr. Zeigler didn't write
9 them, and probably Mr. Burgess, either. Did you have a
10 hand in helping prepare those responses?

11 **A** Yes, me, and my department participated.

12 **Q** All right. And I hold in my hand that document, and
13 it's a modest-telephone-book-sized piece of paper.
14 Would that likely be what you helped prepare and got to
15 me on Sunday?

16 **A** Yeah, probably.

17 **Q** Okay. Thank you. That helps. Now, that said, a couple
18 of clarifying questions, please. Can we agree that the
19 comparative economic analysis document -- I'm just going
20 to call it "comparative analysis" -- the comparative
21 analysis is not an integrated resource plan, is it, Dr.
22 Lynch?

23 **A** "Integrated resource plan."

24 **Q** Well, let me phrase it another way --

25 **A** Yeah.

1 Q -- while you're hesitating. Can we agree that it does
2 not evaluate other resources in the mix, aside from
3 assessing nuclear versus pursuing a gas-resource
4 strategy; it evaluated a gas-resource strategy as the
5 sole alternative?

6 A Well, that document focuses on gas versus nuclear.

7 Q Yes.

8 A That doesn't mean that the company hasn't evaluated
9 these other tools in our plans or that those things
10 aren't reflected in our resource plans.

11 Q Right, no, I didn't mean to suggest otherwise. Just,
12 it's not in this comparative analysis document. Gas is
13 the only alternative to continuing nuclear construction
14 that you evaluated --

15 A Right.

16 Q -- in this document, correct?

17 A Based on the nuclear versus base-load gas, was the
18 comparison that's in that document, yes.

19 Q Right, there you go. Now, can we agree whether or not
20 the nuclear costs that you modeled in the comparative
21 economic analysis included an assumed receipt of a
22 federal production tax credit?

23 A Yes, it did.

24 Q And I hate to use pejorative terms, now, but isn't that
25 kind of like taking welfare? I mean, that is the

1 government writing SCE&G a check to cover part of the
2 cost of the output of the plant. That's like me getting
3 a little AFUDC or income assistance, isn't it?

4 A Is it like taking a tax reduction for mortgages? I
5 don't -- I don't understand. Production tax credits
6 were considered in the evaluation, yes.

7 Q All right. So they subsidize the price of electricity
8 that will be produced by the nuclear units, as you
9 modeled them?

10 A Yes. That's right, of course.

11 Q Okay. Right. So that helps make nuclear look a little
12 bit better, because you've got production tax credits in
13 there, right?

14 A Makes it more economical for our customers, yes.

15 Q That's right, and more justified in your economic
16 analysis, correct?

17 A Oh, certainly.

18 Q All right. Now, in your analysis you assume a fixed
19 capital cost for the nuclear production, don't you?

20 A Yes.

21 Q You don't assume that there will be any further
22 escalation in the capital costs of the nuclear, beyond
23 the costs that are before the Commission today, correct?

24 A Right. Wasn't necessary.

25 Q All right. Well, you say it wasn't necessary, but you

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1 heard other witnesses -- Mr. Marsh, Mr. Byrne, Mr.
2 Lavigne, maybe others beyond that -- acknowledge that
3 there are remaining, outstanding nuclear risks that
4 potentially could affect schedule and cost. Your
5 company acknowledges that, don't they?

6 A Yeah, but I think we acknowledge that -- say that
7 they're minimal at this point.

8 Q Well, but you treated them as zero, for purposes of this
9 analysis, correct? No further escalation in nuclear
10 costs.

11 A It wouldn't affect the results. Didn't need to do it.

12 Q But you didn't it.

13 A I -- it's not reflected, correct. It's not reflected in
14 that report.

15 Q Good. Now, what effect on your analysis would there be
16 if there were a 10 percent -- not a zero, but a 10
17 percent -- escalation in the capital costs of these
18 nuclear units, beyond that which is before the
19 Commission today? Would that have any material effect
20 on your comparative analysis?

21 A So 10 percent, would that -- that would wipe out that
22 \$551 million reduction that we've seen in the budget,
23 and I don't -- it wouldn't affect the decision that is
24 reflected in that report at all, no.

25 Q It wouldn't affect the cost comparison, the levelized

1 cost comparison, in your opinion?

2 A Oh, if you change the capital cost, it'll change all the
3 numbers. It won't affect the conclusion, though.

4 Q Wouldn't affect your conclusion, but it would affect the
5 comparative levelized projected costs of nuclear --

6 A Certainly.

7 Q -- versus the alternative.

8 A Certainly.

9 Q Okay. In a way that was unfavorable to nuclear. 10
10 percent higher costs -- the levelized costs of nuclear
11 are higher.

12 A Would make the -- yes, it would make the nuclear
13 strategy less favorable.

14 Q All right.

15 A But it's not -- it wouldn't overcome the conclusion that
16 it's a good idea to continue with the construction.

17 Q Yes.

18 A To make sure --

19 Q I understood your position there. All right.

20 A Okay.

21 Q Now, how about the base nuclear costs included in your
22 analysis? Does it include AFUDC?

23 A Yes.

24 Q And does it include escalation?

25 A Yes.

1 Q All right. So no increase in the base nuclear -- in the
2 capital cost budget, but it does include escalations
3 that are built into the EPC contract, for example,
4 right?

5 A I guess I misunder- -- AFUDC I consider the capital
6 cost.

7 Q All right. Include AFUDC.

8 A So with all that, Ms. Walker had a schedule, \$5.7
9 billion or something like that.

10 Q Right.

11 A So that's the number I'm using as the cost, capital cost
12 of the nuclear.

13 Q Right. And then escalation, by that I mean not cost
14 overruns or increased costs in the capital budget, but I
15 mean escalations that are taken into account, for
16 example, in the EPC contract, correct?

17 A Right, that's reflected in her schedule, I believe.

18 Q All right. Now, when you make the analysis, because of
19 the Base Load Review Act -- and I guess, just in
20 economic principles -- as you said in your summary,
21 it's, in effect, the to-go costs that are relevant,
22 because we're into this project 25 percent or more of
23 the total expected budget, for --

24 A Right.

25 Q -- example, right? So whatever the alternative is, gas

1 or any alternative, that alternative is burdened by the
2 sunk costs that we've already committed to this project.
3 That's the principle, isn't it?

4 A Yes, we'd have to recover those costs.

5 Q All right. And so you have to recover those costs and
6 you have to figure out how to recover those costs. Now,
7 for example -- you and I have been around awhile -- were
8 you around in the era when a number of the first round
9 of nuclear projects were canceled, and there were
10 efforts to recover abandonment costs?

11 A I'm sure I was around, but not involved.

12 Q Okay.

13 A So I may not know much of what you're --

14 Q Well, those costs, to the extent the Commission was
15 asked by SCE&G or Duke to allow recovery of costs of
16 abandoned proposed units -- and there was going to be a
17 second unit at Summer, wasn't there, in the original?

18 A Yeah, I believe so.

19 Q Okay. So there was some cost associated with that.
20 Those costs were recovered by amortizing them over a
21 period of time and including them in rates, correct?

22 A Yeah, I don't know what cost involved the second unit.
23 I don't know if you were -- if that was --

24 Q No, I wasn't. I wasn't asking for specifics, but just
25 as a matter of principle, when you recover those sunk

1 costs and when you did recover those sunk costs, or
2 others recovered those sunk costs in the first
3 generation, they recovered them from ratepayers not by
4 saying, "Write us a check tomorrow"; they amortized them
5 over a period of time. Correct?

6 A And you're not talking about SCE&G, right? Summer 1
7 came on-line and is in rate base and progressed --

8 Q Understood. Understood.

9 A There's other companies that had to recover. But with
10 the Base Load Review Act, my understanding is that the
11 bondholders who lent us that money will get their money
12 back; and the stockholders who lent their money, they
13 could be reimbursed their funds, too. The Base Load
14 Review Act, I think, guarantees that.

15 Q Exactly. I mean, no dispute there. The Base Load
16 Review Act, in fact, provides that if there's an
17 abandonment of the plant and the company comes back to
18 the Commission, they're entitled to recover those sunk
19 costs, unless the decision to abandon was deemed to be
20 imprudent. I'm paraphrasing, but it's basically the
21 principle you've just said.

22 A So if we switched to natural gas --

23 Q Yes.

24 A -- and abandoned the construction, the cost that's
25 already spent on the plants would be charged to

1 customers, going forward, from what I understand.

2 Q Exactly. So one way or the other, in your comparative
3 analysis, you add -- you tack onto the cost of that
4 alternative recovering those sunk or abandoned plant
5 costs. That's just what you've got to do.

6 A Yeah, the basic idea was, if you continued the nuclear
7 strategy, this is what -- the revenue requirements that
8 our customers have to pay.

9 Q Yeah.

10 A If you switch to gas, then here's all the cost that the
11 customers would have to pay.

12 Q Yeah, gotcha.

13 A And that would include the sunk costs associated with
14 the nuclear.

15 Q All right. And in your comparative analysis, which is
16 in JML-4, you assume that that amortization takes place
17 over a period of 40 years, don't you?

18 A That's correct.

19 Q Now, do you know whether or not utilities that recovered
20 abandoned plant costs in that first round actually
21 amortized those costs over far shorter periods of time
22 than the 40 years?

23 A I have no idea.

24 Q If you, in your comparative analysis or a comparative
25 analysis, modeled amortization not over 40 years but

1 over ten years, would that affect the outcome
2 comparison?

3 A Yes, it would move the cost up closer. The present
4 value would be larger, so it would affect it.

5 Q How would it affect it?

6 A Well, it would increase the present value of those
7 costs, so it would disadvantage the gas strategy.

8 Q Wouldn't it reduce the levelized total cost advantage of
9 -- wouldn't it reduce the levelized total cost advantage
10 of nuclear by recovering them quicker, not spreading
11 them over 40 years?

12 A No, it would increase the cost to the gas strategy, make
13 nuclear look better.

14 Q You think. Okay.

15 A Yeah. I was told that ten years is too short and to use
16 40.

17 Q You were told to use 40?

18 A Forty. The Rate Department says 40 --

19 Q Okay.

20 A -- is probably what would happen.

21 Q All right. Do you know what -- would you accept --
22 well, do you have any understanding of whether or not
23 utilities before this Commission in that 1980s era ever
24 were allowed to amortize their canceled plant costs over
25 a period of 40 years?

1 A I have no idea.

2 Q Okay.

3 A I'm not sure it's relevant to today, anyway.

4 Q Okay. Now, your comparative analysis also assumes that

5 you're going to add gas units of a certain size, and

6 that you will phase those two gas units at the same

7 point that you would have phased in Units 2 and 3 of the

8 nuclear plant.

9 A Right. We assumed that we'd have a 614 megawatt

10 combined-cycle unit in '17 and another in '18.

11 Q Okay.

12 A So, megawatt for megawatt.

13 Q All right. Now, you have gas units on your system now?

14 A Yes.

15 Q How big are they? What's the megawatt capacity?

16 A Jasper is 875. The Urquhart combined-cycle is --

17 [indicating] give me a second. It's 458 megawatts for

18 Urquhart.

19 Q Okay. You have any other gas units on your system?

20 A Peaking units, yes.

21 Q How big or small would the peaking units be, just

22 typically? Not specifically.

23 A A lot of small ones in the teens, 20 megawatts. That

24 sort of thing.

25 Q All right.

- 1 A Hagood is our biggest at about -- between 90 and --
- 2 Q So you have a range of gas units, a range of scale of
- 3 gas units available, and they may go up to 800
- 4 megawatts, but you have a number of choices for gas
- 5 units that are smaller than the 600-plus-megawatt-size
- 6 units you assume both have to come on at the same time
- 7 as the nuclear units would come on, don't you?
- 8 A Yeah. Yes, it ranges, yes.
- 9 Q Okay. Yet, you didn't do any analysis for other
- 10 capacity expansion strategies that might be more phased,
- 11 if there were indeed reductions in demand. You assumed
- 12 the full-size gas units came on precisely at the time
- 13 that the full-size nuclear units came on?
- 14 A Yeah, so we thought matching up the megawatts would be a
- 15 good way to see the advantage or disadvantage of
- 16 switching to gas.
- 17 Q Okay. But smaller gas units would allow you more
- 18 flexibility to bring them on to actually match demand
- 19 growth, wouldn't they?
- 20 A Well, you -- no, you'd have to put a combined-cycle in,
- 21 which is going to be around 600 megawatts. Because you
- 22 wouldn't want a peaker. If you want something to run
- 23 base-load, it would have to be larger.
- 24 Q Okay. Could you put on one base-load and then a smaller
- 25 one if demand were reduced, instead of putting on two

1 full-sized --

2 A I'm sure we wouldn't do that, because we need base-load
3 on the system.

4 Q You're going to need all the base-load that you're going
5 to get from the two Summer units?

6 A Well, that will be enough for a while.

7 Q For a long --

8 A We're retiring --

9 Q Excuse me.

10 A We're retiring 730 megawatts of coal plants before then.

11 Q Right. And your partner's trying to sell off part of
12 their capacity because they don't need it. Santee
13 Cooper?

14 A Oh, but it was a load issue for them. That's not --
15 that's a different matter. Talking about Santee Cooper?

16 Q Yes.

17 A Oh, that's a different issue altogether. And they
18 would've preferred to have the load and have the
19 capacity, I'm sure.

20 Q And then the reserve margin, you assume a reserve margin
21 in your analysis. Is it fair to say it's approximately
22 14 percent?

23 A Minimum of 14 percent, yes.

24 MR. GUILD: One moment, Mr. Chairman, please.

25 CHAIRMAN WRIGHT: Mr. Guild, just a quick

1 question. Do you have a few more minutes you're
2 going to be doing cross?

3 CHAIRMAN WRIGHT: If you can just give me one
4 moment, Mr. Chairman, and let me just consult, and
5 I may be at an end to mine.

6 CHAIRMAN WRIGHT: Okay.

7 MR. GUILD: Thank you.

8 [Brief pause]

9 Mr. Chairman, that's all I have. Dr. Lynch,
10 thank you, very much, for answering my questions.

11 CHAIRMAN WRIGHT: Thank you. We're going to
12 take a break now, to give the court reporter a
13 chance to catch her breath. How about 3:40, ten
14 minutes.

15 [WHEREUPON, a recess was taken from 3:30
16 to 3:40 p.m.]

17 CHAIRMAN WRIGHT: Please be seated. We are
18 going to reconvene the hearing. And I believe Ms.
19 Greenlaw -- I mean, Mr. Elliott, you're up.

20 MR. ELLIOTT: No questions of Dr. Lynch.

21 CHAIRMAN WRIGHT: Okay. Ms. Greenlaw?

22 MS. GREENLAW: I'm going to defer at this
23 time. Thank you.

24 CHAIRMAN WRIGHT: Okay.

25 MS. GREENLAW: Not defer -- sorry. I have no

1 questions at this point.

2 MS. HUDSON: No questions from ORS.

3 CHAIRMAN WRIGHT: All right. Commissioners.
4 Commissioner Mitchell.

5 COMMISSIONER MITCHELL: Thank you, Mr.
6 Chairman.

7 EXAMINATION

8 BY VICE CHAIRMAN MITCHELL:

9 Q Dr. Lynch, if you would, just -- you mentioned the
10 PROSYM model, and if you could just be brief, could you
11 just tell me a little bit about that, the explanation of
12 that?

13 A Okay. It simulates the dispatch of our units as a model
14 we license from Ventyx, and it's used in most utilities
15 -- all the big utilities have the model and use the same
16 tool. In that model, we describe all the plants that
17 are going to be dispatched, what the constraints are on
18 them, ramp time, ramp-up, minimum downtime. We have
19 heat rate curves, so depending on how much we're putting
20 out. You have a minimum level of output, and of course,
21 the maximum rating of the plants. And then the heat
22 rate curve would transfer the fuel, to tell you how much
23 fuel you need to produce so many kilowatt-hours. What
24 else is in there? Your variable O&M, all the fuel. The
25 time periods to start units, other than coal plants.

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1 You can't just turn on a dime. So all those
2 constraints, all that, and you feed in the load that you
3 want to meet, you know, how many kilowatt-hours you have
4 to produce. You can also model a market where you can
5 buy and sell on the margin, to augment that it's --
6 whether it's more economical to purchase -- it might not
7 start up a unit and purchase something, or if you can
8 sell something, you might try to sell it off. So
9 there's a minimal amount of market activity.

10 So what we use it for, then, is just to simulate
11 the dispatch of all the models, figure out what the fuel
12 costs are going to be, what the load on the plants is,
13 how much coal, how much gas, and what the cost of all
14 the fuel is. So that sort of drives those studies.

15 VICE CHAIRMAN MITCHELL: Thank you. Thank
16 you, Mr. Chairman, that's all I have.

17 CHAIRMAN WRIGHT: Commissioner Howard.

18 EXAMINATION

19 BY COMMISSIONER HOWARD:

20 Q How you doing, Dr. Lynch?

21 A Good, Commissioner.

22 Q At one time we were talking about the price of uranium
23 going up because of the nuclear renaissance. What do
24 you see as the price -- the future price of uranium?

25 A I know that the cost today is a little bit less than

1 what we had in 2008, but not much to make a significant
2 difference on the cost. I'm told that it'll increase,
3 but not significantly. And it's a small part of the
4 plant, so I don't -- you know, the cost of the nuclear
5 plant fuel is a small part, so we don't --

6 **Q** Right.

7 **A** -- really worry about that. So I don't see a problem,
8 I've been told, to worry about. But I can't give you
9 good answer because I don't have, you know, that
10 forecast with me.

11 **COMMISSIONER HOWARD:** Thank you.

12 **CHAIRMAN WRIGHT:** Commissioners, anything?

13 [No response]

14 Any redirect?

15 **MR. ZEIGLER:** Mr. Chairman, one question for
16 Dr. Lynch.

17 **REDIRECT EXAMINATION**

18 **BY MR. ZEIGLER:**

19 **Q** Is this on? Yes. Oh, good. Dr. Lynch, you were asked
20 about the impact of changes in the capital costs of the
21 plants on the outcome of your analysis. Would you
22 explain why your answer was that you didn't think those
23 changes would have an impact that would change your
24 result?

25 **A** Well, it wouldn't change the conclusion, because I think

1 the conclusion for the company isn't based on that
2 study. I mean, I think it's based on a lot of the facts
3 and issues in the utility business, the energy market,
4 today. For example, we have low gas prices, but the
5 risk of higher gas prices is recognized by everybody.
6 It wouldn't surprise me if, in several years, you have
7 significantly higher gas prices than you do today. And
8 you have to worry about the CO₂ costs. The EPA has
9 determined that emitting CO₂ endangers the public health,
10 and the Supreme Court tells them that if that's their
11 finding, then under the Clean Air Act they have to
12 regulate CO₂. And even just this year, in June, the US
13 Court of Appeals in the DC Circuit, I believe, gave a
14 major win to the EPA, saying that their interpretation
15 of the Clean Air Act and how they are implementing
16 regulations, putting regulations in place to control CO₂,
17 that they're doing everything exactly right, legally.
18 And I think there was a three-judge panel that
19 unanimously said that. So I'm expecting the EPA to take
20 that and go forward.

21 Then the company's looking at, as I mentioned to
22 Mr. Guild, this 730 megawatts of coal plants that we're
23 being forced to retire. Then on top of that, when we
24 look at the nuclear plant, one-third of it essentially
25 is constructed already, so by the end of the year, we'll

1 have spent one-third of the costs. And when you look at
2 the remaining costs, we seem to be 9 percent below where
3 we originally started, so the project is going very
4 well. And then on top of that, if you were going to
5 build the plant today, if you were going to start
6 building nuclear today, at least according to the EPA_[sic],
7 our costs are about -- they're more than 30 percent
8 below what the EEI says is the cost going forward.

9 So I'm thinking management is looking at all those
10 issues. You know, on top of that, I'd like to get on
11 the record, Duke Power just issued their IRP a couple of
12 weeks ago, and in their resource planning they have
13 nuclear power in their future, too. They see, because
14 of the carbon-constrained future, they need nuclear
15 power in their expansion plans, and their decision and
16 their analysis isn't encumbered by \$2 billion having
17 already been spent on that strategy. So I'm seeing,
18 when management looks at all of those things, it almost
19 doesn't matter what this study produces, even though the
20 study we did produce -- it supported management decision
21 that every cell in those 27 scenarios showed nuclear was
22 positive. And that's why I'm saying, you can assume
23 construction costs of 500. Suppose you lost that 500 or
24 \$1 million, so 10 percent cost increases. One or two of
25 those cells in that 27-cell study that we did, where

1 every one of them was positive for nuclear, a couple of
2 them might turn negative, a negative benefit. Gas,
3 under those conditions. But when management looks at
4 that 27-cell study and then they look at that list of
5 things that I just ticked off, you know, it doesn't
6 matter what the study says. You have to go forward with
7 the nuclear. Based on what we see in the world today,
8 we have to go forward. It's just necessary. And that's
9 why I was saying it didn't matter; 10 percent just is
10 not an issue. Wouldn't affect the decision.

11 MR. ZEIGLER: Thank you, Dr. Lynch. No
12 further questions.

13 MR. GUILD: Follow-up question, Mr. Chairman?

14 CHAIRMAN WRIGHT: Yes, sir. Mr. Guild.

15 **RE CROSS EXAMINATION**

16 **BY MR. GUILD:**

17 **Q** Well, Dr. Lynch, Duke Power -- did they say in that IRP
18 that they weren't going to go with nuclear unless they
19 got an equivalent statute in North Carolina to the Base
20 Load Review Act, that would give them an ability to
21 shift risk to ratepayers to the extent that it's done
22 under our early recovery law in South Carolina?

23 **A** Give me a second, and I'll -- I can tell you what I read
24 [indicating].

25 **Q** That's my question, now, Mr. Lynch. There are probably

1 a lot of things you read in there, but that's not really
2 what I'm asking. I'm asking, did Duke acknowledge that
3 they needed -- what they call super-CWIP in North
4 Carolina -- a base-load review act as generous to them
5 in North Carolina as our Base Load Review Act is to
6 utilities here? Did they say that?

7 A Well, I don't know. I know they did say that nuclear is
8 economic in their resource plan, but in terms of
9 recovering the cost and how to do that, I don't know if
10 that's mentioned in here, or not. I would suspect no,
11 but --

12 Q Are you aware that their management has made that
13 assertion that they will not go forward with the Lee
14 units in Cherokee County, those new AP1000 units, unless
15 they get a base-load review act in North Carolina
16 equivalent to the risk-shifting law here?

17 A I can see that execution of the best plan, it might be
18 problematic for them, so -- but I'm not aware of that,
19 no. That's -- I don't doubt it, though.

20 MR. GUILD: No further questions, Mr.
21 Chairman.

22 CHAIRMAN WRIGHT: Anyone else?

23 [No response]

24 All right. Thank you, very much.

25 MR. ZEIGLER: We'd ask the witness be excused.

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DIRECT EXAMINATION**BY MR. GUILD:****Q** Good afternoon, Dr. Cooper.**A** Good afternoon.**Q** Would you state your name for the record, please?**A** Dr. Mark N. Cooper.**Q** All right. And where do you live?**A** 504 Highgate Terrace, in Silver Spring, Maryland.**Q** All right. And would you -- have you been asked by Sierra Club to perform certain analyses and prepare certain testimony in this case?**A** Yes, I have.**Q** All right. Among those, were you asked to prepare and did you prepare direct testimony of 26 pages and 11 exhibits?**A** Yes, I did.**Q** Did you prepare surrebuttal testimony that was filed on or about September 6th of this year, consisting of 15 pages and exhibits?**A** Yes, I did.**Q** If I asked you the questions that appear in those prefiled documents today, would your answers be the same?**A** Yes, they would.**Q** Do you have any corrections or additions you need to

1 to have prepared it in written form, but I could
2 certainly ask him these questions orally, and Mr.
3 Zeigler would have no further assistance with a
4 written document in that instance.

5 CHAIRMAN WRIGHT: Could you do it in less than
6 30? Out of respect for trying to get him to the
7 plane?

8 MR. ZEIGLER: Certainly. 15 or 20 minutes
9 would be helpful. I'm not sure how --

10 CHAIRMAN WRIGHT: Why don't we say a quarter
11 after [4:15]? Can you do that? Can you do it by a
12 quarter after [4:15]?

13 MR. ZEIGLER: Yes, sir. We'll certainly try.

14 CHAIRMAN WRIGHT: All right. We'll stand in
15 recess.

16 MR. GUILD: Mr. Chairman --

17 CHAIRMAN WRIGHT: Yes.

18 MR. GUILD: -- is it possible for him to
19 provide his summary before we take that break?

20 CHAIRMAN WRIGHT: Yes, please. Yes.

21 MR. GUILD: All right.

22 BY MR. GUILD:

23 Q Dr. Cooper, you have a summary prepared for your direct
24 and your initial surrebuttal testimony?

25 A Yes, I do.

1 Q Can I start your -- you have some exhibits you want to
2 show --

3 A Well, I'm going to do this differently. I'm going to --
4 thank you, Mr. Chairman and members of the Commission.
5 It's a pleasure being back in South Carolina. It's been
6 awhile since I've testified here.

7 What I thought I would do is briefly walk through
8 my conclusions and recommendations, and then show some
9 slides about the data. I think it's important in a
10 really big case to see it first, and then we can look at
11 the bits and pieces of data. So I'll go through the
12 summary, and then I can go over there and run the
13 slides, rather than have my technology-challenged
14 attorney try and run that.

15 [Laughter]

16 Q I'll accept that criticism. Please provide your
17 summary, Dr. Cooper.

18 A Okay, thank you. So I will briefly summarize my
19 approach and conclusions, and then show a few slides
20 that support my recommendation that the construction of
21 Summer Units 2 and 3 be canceled and a lower-cost
22 approach be taken to meeting the need for electricity in
23 South Carolina that is both more consumer friendly and
24 more environment friendly.

25 The Base Load Review Act carved out a limited safe

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1 harbor for nuclear construction by suspending the used-
2 and-useful standard and guaranteeing advance cost
3 recovery of costs that had been approved. It was not a
4 blank check. It preserved the prudence review of
5 proposed construction, it required cost overruns to be
6 found not imprudent, and it left the general utility
7 regulatory principles of just, reasonable, and prudent,
8 in place.

9 Prudence, in the competitive market, which is what
10 utility regulation seeks to emulate, is a vigilant and
11 rigorous taskmaster. An investor must evaluate
12 decisions constantly to ensure that what seemed
13 reasonable yesterday is reasonable today, in light of
14 current facts and knowledge. A project that is no
15 longer prudent must be canceled, in the competitive
16 marketplace, because its costs will not be recoverable,
17 if the marketplace is competitive. Consumers will have
18 lower-cost options, and so you can't pursue the
19 imprudent project. Of course, if everybody made the
20 same mistake, then you might get some of your costs
21 back, but not all.

22 By 2010, it was clear that nuclear construction was
23 uneconomic. Demand growth had slowed dramatically. Gas
24 prices had plummeted. The potential for alternatives,
25 like efficiency and renewables, had grown, and their

1 cost was declining, too. Climate change legislation
2 with a big carbon tax had stalled. More importantly,
3 the most likely form that climate policy was going to
4 take -- indicated in the US by the Waxman-Markey Bill --
5 had very substantial mandates for efficiency and
6 renewables, which would've diminished any impact of the
7 carbon tax, and it would have dramatically reduced the
8 demand for central-station facilities.

9 Under the Base Load Review Act, we cannot look back
10 to evaluate prudence in the past, but we must look
11 forward. Even today, I believe that, with \$2 billion in
12 sunk costs and the additional cancellation costs, Summer
13 2 and 3 are uneconomic. The ratepayers of South
14 Carolina will be better served if the construction is
15 canceled and lower-cost alternatives are used to meet
16 the future needs for electricity.

17 The decision-maker must take the full range of
18 alternatives available into account. That is what a
19 prudent decision will do today. Look at everything,
20 carefully, and totally.

21 The amortization of those sunk costs, which is
22 necessary under the Base Load Review Act, should be done
23 in a sensible manner that minimizes the impact on
24 consumers over the long term. The alternative scenarios
25 should match supply and demand very carefully, seeking

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1 the best way to meet demand at the lowest cost. And gas
2 is still available. It is extremely cheap today. And
3 the short period of very high-priced gas is actually the
4 exception rather than the rule, in the gas market.

5 So when you combine all of these things, I believe
6 that the ratepayers of South Carolina would actually be
7 a billion dollars better off if we did the prudent
8 thing, canceled the reactor, found an alternative path
9 that relied on gas, renewables, efficiency, and met the
10 carbonization goals -- the decarbonization goals in the
11 least-cost manner. Thank you.

12 Q Dr. Cooper, you had some slides that would accompany
13 that summary? And you don't trust me to run the
14 machine?

15 A Well, I've been dealing with you for years.

16 MR. GUILD: Enough criticism, Mr. Chairman.

17 [Laughter]

18 WITNESS: Okay. I didn't ask how do you --
19 oh, there you go. Okay. So essentially, I made
20 four empirical statements -- or four or five
21 empirical statements in my -- well, having
22 criticized my lawyer, I now have to get rid of this
23 -- this -- [indicating]. Well, how do we get rid
24 of that?

25 [Brief pause]

1 Okay. We're going to have this adornment in
2 the middle of it.

3 [Laughter]

4 [Reference: Cooper Presentation Pg 2]

5 These are, from the company's records, the
6 projections of demand each year starting in 2008.
7 By 2010, we have reduced our projected firm peak
8 demand by almost one of the units at Summer --
9 Summer 2. By this year, we have reduced the
10 projected peak demand by one and a half of those
11 units. This is a substantial, material change in
12 fact that ought to be taken into account in your
13 decision-making, demand-side.

14 [Reference: Cooper Presentation Pg 3]

15 These are natural-gas prices. Again, I have
16 gone back to the company's record. We asked them a
17 question; I used EIA data. The EIA never projected
18 gas prices anywhere near as high as the company did
19 in 2008. So the company likes to say that EIA was
20 wrong? Well, the answer is, the company was way
21 more wrong than EIA was in 2008.

22 These are the Henry Hub prices. So that means
23 you can go on Henry Hub and buy gas at that price
24 today, out through 2020.

25 The middle curve -- the top curve is base-case

1 gas, from the 2008 proceeding. That curve is 2010.
2 By 2010, the price of gas had plummeted, and it's
3 continued to go down. As Mr. Lynch said, the
4 company's gas price -- that's the price they used
5 in the current analysis. So this is no surprise.

6 [Reference: Cooper Presentation Pg 4]

7 Oh, and here's the graph that shows all of the
8 other projections, and the green triangles are the
9 company's 2008 prediction. This is EIA's 2008
10 prediction. This is EIA's projection today. And
11 this is the New York Mercantile Exchange
12 [indicating]. And if you're a capitalist and you
13 believe in a capitalist society, the New York Merc.
14 is the best market you're going to look to, because
15 that's where the price is set.

16 [Reference: Cooper Presentation Pg 5]

17 Now, people in the utility industry have
18 looked -- have been looking at this. You've heard
19 about the nuclear renaissance. There were a lot of
20 people; there's almost nobody left. Three of the
21 five members of the AP1000 group have been kicked
22 out by Westinghouse because they didn't sign EPCs.
23 And this is the CEO of Exelon, that fellow from the
24 Northeast who Mr. Mahr said he didn't want to let
25 his view of the world be imposed on South Carolina.

1 But this is his view of the world, and it basically
2 shows you 2008 to 2010. So by 2010, in his view,
3 there was an immense amount of low -- and the cost
4 curve here is the cost per ton of carbon. So he's
5 looking at the world through this carbon abatement
6 curve. Right? And what he finds is -- and that
7 big blue thing is nuclear. He sees nuclear costs
8 rising. The company will tell you that theirs
9 hasn't risen. I think there is some dispute about
10 that.

11 But the interesting thing is the amount of
12 low-cost alternatives, that he sees, has increased
13 dramatically. And you'll observe on this graph the
14 interesting phenomenon of costs that have a
15 negative cost per ton of carbon. How can something
16 have a negative cost per ton of carbon? The answer
17 is simple. The electricity produced by those
18 alternatives is below the average cost to supply
19 today. So if you add efficiency, you not only kick
20 out a ton of carbon, but you also get a lower
21 average cost. You lower the bill to the consumer.
22 And so this is an efficient way to approach the
23 decarbonization challenge. And this is 2010. So
24 this is not a surprise. It has been happening.

25 [Reference: Cooper Presentation Pg 6]

1 Again, this is PJM. They are a different
2 utility. They have their own view of supply curve.
3 This is, again, the cost of carbon supply curve.
4 And you see the same phenomenon.

5 I can produce these graphs, as I do in my
6 testimony, from EIA, from Lazard on Wall Street,
7 from the National Academy of Sciences. Everybody
8 in the world sees this supply curve. And the
9 essence of prudence is making decisions that the
10 prudent people around you are making, and I would
11 submit that this is good evidence that there's a
12 lot of opinion among the experts, the stakeholders,
13 et cetera, that this is the supply curve you ought
14 to be looking at, and -- oh, by the way -- you
15 probably should've seen this supply curve in 2010.
16 We're here in 2012 and we have to carry the cross.

17 I think that's the last one for now. Yeah.
18 The last slide will be from the sur-surrebuttal
19 testimony.

20
21
22
23 [PURSUANT TO PREVIOUS INSTRUCTION, THE
24 PREFILED DIRECT TESTIMONY OF MARK N.
25 COOPER, Ph.D., FOLLOWS AT PGS 949-974]

BEFORE THE
SOUTH CAROLINA PUBLIC SERVICE COMMISSION
DIRECT TESTIMONY
OF
DR. MARK COOPER
ON BEHALF OF THE SIERRA CLUB
DOCKET NO. 2012-203-E

I. QUALIFICATIONS

Q. Please state your name and address.

A. My name is Dr. Mark Cooper. I reside at 504 Highgate Terrace, Silver Spring, Maryland.

Q. Briefly describe your qualifications

A. I have a Ph.D. from Yale University and have been providing economic and policy analysis for energy and telecommunications for over thirty years. I have been the Director of Energy and the Director of Research at the Consumer Federation of America for 27 years, although the opinions I express in this testimony are my personal opinions and not those of the Consumer Federation. I am a Fellow at various universities on specific issues, including the Institute for Energy and the Environment at Vermont Law School. I have testified over 100 times before public utility commissions in 44 jurisdictions in the U.S. and Canada on energy and telecommunications issues and about twice as many times before federal agencies and Congress on a variety of issues, including energy and electricity. In the past few years I have testified on

nuclear construction cost issues before regulators and legislators at the federal and state levels in the U.S. and Canada and published papers and articles in professional journals.

Q. Please describe your activity with respect to electricity economics and resource acquisition.

A. One of the first public utility commission proceeding I participated in over a quarter of a century ago involved the prudence and economic viability of Grand Gulf 2.¹ The most recent proceedings I have testified in involved the same issues with respect to the Turkey Point and Levy reactors in Florida.² In the intervening years I have testified about and published numerous articles on nuclear economics,³ natural gas,⁴ energy efficiency,⁵ renewables⁶ and electricity restructuring.⁷ My complete Curriculum Vitae is provided as Exhibit MNC-1.

¹ "On Behalf of Mississippi Legal Services Coalition in the Matter of the Citation to Show Cause Why the Mississippi Power and Light Company and Middle South Energy Should not Adhere to the Representation Relied Upon by the Mississippi Public Service Commission in Determining the Need and Economic Justification for Additional Generating Capacity in the Form of A Rehearing on Certification of the Grand Gulf Nuclear Project," *Before the Mississippi Public Service Commission*, Docket No. U-4387, August 13, 1984

² "Direct Testimony of Dr. Mark N Cooper in Re: Nuclear Plant Cost Recovery for the Southern Alliance for Clear Energy," *Before the Florida Public Service Commission*, FPSC Docket No. 100009-EI, August 2010; "Direct Testimony of Dr. Mark N cooper in Re: Nuclear Plant Cost Recovery for the Southern Alliance for Clear Energy," *Before the Florida Public Service Commission*, FPSC Docket No. 090009-EI, July 15, 2009

³ "Economic Advisability of Increasing Loan Guarantees for the Construction of Nuclear Power Plants," *Domestic Policy Subcommittee, Committee on Oversight and Government Reform, U.S. House of Representatives*, April 20, 2010

⁴ "Energy Market Manipulation and Federal Enforcement Regimes," *Committee On Commerce, Science And Transportation, United States Senate*, June 3, 2008; "Direct Testimony Of Dr. Mark N. Cooper On Behalf Of The Attorney General Of Oklahoma, *Before The Oklahoma Corporation Commission* Application Of Ernest G. Johnson, Director Of The Public Utility Division, Oklahoma Corporation Commission, To Require Public Service Company of Oklahoma To Inform The Commission Regarding Planning Of Energy Procurement Practices And Risk Management Strategies And For A Determination As To Appropriate Methods To Lessen The Impact Of Energy Price Volatility Upon Consumers, Cause No. Pud 2001-00096, May 18, 2001

⁵ "Building Energy Performance Standards," *before the Subcommittee on Energy Regulation of the Committee on Energy and Natural Resources, United States Senate*, June 26, 1980; "Prudent Resource Acquisition in a Complex Decision Making Environment: Multidimensional Analysis Highlights the Superiority of Efficiency," *Current Approaches to Integrated Resource Planning, 2011 ACEEE National Conference on Energy Efficiency as a Resource*, Denver, September 26, 2011

⁶ Risk, Uncertainty and Ignorance: Analytic Tools for Least-Cost Strategies to Meet Electricity Needs in a Complex Age, *Variable Renewable Energy and Natural Gas: Two Great Things that Go Together, or Best Not to Mix Them*. NARUC Winter Committee Meetings, Energy Resources, Environment and Gas Committee, February 15, 2011

⁷ "Initial Comments of the Consumer Federation of America," *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Federal Energy Regulatory Commission, Docket No. RM-01-12-000, October 15, 2002; "An Economic Explanation of Why the West and South Want to Avoid Being Infected by FERC's SMD and Why Market Monitoring is Not an Effective Cure for the Disease," *SMD Market Metrics Conference*, Federal Energy Regulatory Commission, October 2, 2002; "Reply Comments of the Consumer Federation Of America," *before the Federal Energy Regulatory Commission, San Diego Gas & Electric Company, Complaint, v. All Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange*, Docket Nos. EL00-95-000 et al, 2000;

II. PURPOSE AND OUTLINE OF THE TESTIMONY

Q. What is the purpose of your testimony?

A. I have been asked by the Sierra Club to evaluate whether the cost overruns that South Carolina Electric and Gas (SCE&G, the company or the utility) seeks to recover from ratepayers are just, reasonable and prudent. My review examines the costs from the narrow perspective of the Base Load Review Act (BLRA) and the broad perspective of public utility regulation. I conclude that from both points of view the cost overruns are not prudent. Therefore they should not be recovered from SCE&G ratepayers.

Q. Please describe the history of rate setting for this project under the BLRA that brought it to this point.

A. While the BLRA represented a dramatic change in the way rates are set for new nuclear reactors built in South Carolina, it did not abandon the fundamental concepts of just, reasonable and prudent that govern the setting of utility rates. Advanced cost recovery under the BLRA gives nuclear costs very special treatment, but it is not a blank check and it does not diminish the obligation of the utility to ensure that it delivers the least cost electricity to ratepayers.

This cost overrun proceeding signals to the commission that the utility has failed to continue to practice the cost vigilance it is obligated to exercise. When the contingency cost pool that the Utility proposed in the initial BLRA proceeding (Docket NO. 2008-196-E) was rejected by the South Carolina Supreme Court, the utility quickly updated its cost estimate (Testimony of Kevin B. Marsh, Docket No. 2012-203-E) p. 7, pointing to Order No. 2011-345).

It took a second bite at the apple and chose to increase its cost estimate by \$174 million to establish a cost basis of \$4.3 billion.⁸

A mere two years later, it is back asking for another \$283 million, a cost increase of 6.6 percent. With this request, the cost overruns have now driven the total cost of the project above the original cost estimate plus the contingency cost pool. The BLRA requires a prudence review of the increase in costs and this is the moment for a thorough review of the cost and economic viability of the project.

Q. Are the cost increases prudent from the narrow view of the BLRA?

A. No, they are not. I show in my testimony that there are numerous ways in which the costs the utility now seeks to recover from ratepayers should have been anticipated in the original cost estimate, but were not or have been caused by actions of the utility or its vendors. Ratepayer should not be held responsible for the burden of these actions.

In addition, there is an even more fundamental reason that these costs should not be recovered from ratepayers – the overall project is no longer prudent. Although the BLRA gave nuclear reactor construction special treatment in the cost review process, it did not alter the underlying principles that allow recovery of only just, reasonable and prudent costs. The obligation that a project be prudent is continuous, not a one-shot determination. When economic conditions change projects that have become economically unattractive should be abandoned.

Moreover, the BLRA itself recognizes this principle in expressly allowing the recovery of costs incurred by the utility where a plant has been abandoned so long as the utility proves “the decision to abandon the construction of the reactor was prudent.”

⁸ Marsh, pp. 7-8 describes the cost increase as follows, “In addition, in the 2010 update proceeding, the Company identified and itemized approximately \$174 million in costs to specific cost categories for the project that it would have accounted for using owner’s contingency cost before the court decision.”

plus the costs that have been sunk into the nuclear reactor. This approach to project review (modified by the special treatment of sunk nuclear costs) rests on the fundamental economics of market behavior, which provides the basis for the broad principles of utility regulation. I believe it is consistent with the law in South Carolina as I read it. Legal counsel has indicated to me that he agrees with this view.

Q. Do you believe that the construction of Summer 2 & 3 is the least cost approach to meeting the need for electricity in South Carolina?

A. No, I conclude that Summer 2 & 3 will cost SCE&G ratepayers far more than readily available alternatives. I present preliminary estimates by adjusting the estimates from the original BLRA proceeding. Since the company analysis focused on natural gas as the primary alternative, I provide estimates of the cost of nuclear compared to gas in light of the dramatic decline in projected gas prices. The recent developments make the assumption of high gas prices that were central to the economic analysis in 2008 very doubtful at best. Under the current projections for gas prices, the gas option would be over four \$4 billion less costly than nuclear. Other factors could raise the consumer savings to \$8 billion more than the cost of natural gas over the 40 year life of the new reactors. I also show that independent analyses of the likely revenue requirement of nuclear and gas prepared in the past year support this conclusion.

Other factors, like falling demand and declining cost of alternatives, could lower the cost of meeting the need for electricity with alternatives even more. Simply put, Summer 2 & 3 are far from the least cost option and even with the sunk cost considered, it is very likely that SCE&G ratepayers would be better off if the reactors construction is halted.

Q. Why do you qualify your conclusion by saying "it is very likely ratepayers will be much better off?"

A. My evidence gives a strong indication of what the outcome of a thorough economic analysis would conclude because SCE&G has not done a detailed economic evaluation as it should and because many of the factors that will affect the final sunk costs are hidden behind a veil of confidential secrecy. The magnitude of the sunk costs and other obligations that SCE&G has incurred with the execution of the project to date are unclear, but there is a very good chance that they are substantially less than \$8 billion, which means that the ratepayers would be better off if the utility abandoned the project.

I base these statements on the comparison with gas, since that was the primary alternative the utility identified when it sought cost recovery for the project, but there could be even less costly options available today that a comprehensive economic analysis of all the options would reveal. Unfortunately, the utility has failed to present an economic analysis of the overall project. It should have done so in its Integrated Resource Plan; it did not. It could have done so as part of this proceeding; it did not. I recommend that the Commission order it do so as part of this proceeding and not make a decision on recovery of these cost overruns until it does so.

Time is of the essence. Because of the structure of the BLRA, the longer the utility delays in accepting the fact that the nuclear reactors are no longer the least cost option, the heavier the uneconomic burden that will be placed on ratepayers and the state economy. Under the BLRA, arguably the utility can charge ahead and complete the project in spite of the fact that it is not economic and there is nothing the commission can do to stop it from recovering the costs approved up to the original cost (with inflation adjustments). The only thing it can do to protect the ratepayers from harm, is require the utility to do the proper economic analysis and reject the

recovery of cost overruns, since increasing the cost of a project that is already not economic is the height of imprudence.

Q. How is the remainder of your testimony organized?

A. I begin with the broad view of regulation under the public utility act. In the next section I discuss why utility regulation is based on the principle that rates must be just, reasonable and prudent and how these principles are related to competitive market principles. I then show that dramatic changes in market conditions have undermined the economic attractiveness of nuclear reactor construction. Finally, I turn to the narrow view of cost recovery under the BLRA. I show that there are a variety of reasons the specific cost increases are imprudent and should not be recovered from ratepayers.

III. THE CONSUMER PROTECTION FUNDAMENTALS OF UTILITY REGULATION

Q. Why are utility rates regulated?

A. Because electric utility service has long been viewed as a natural monopoly, it has been delivered to consumers in areas where utilities are given franchises as the monopoly service provider. The rates, terms and conditions of service are regulated, as are many of the investment decisions, since the delivery of service to consumers is not a competitive activity. Since there is no competition, consumers must be protected from the natural tendency of monopoly service providers to charge whatever the market will bear or provide poor service. Thus, public utility ratemaking is fundamentally consumer protection and it is constructed to give consumers the same protections that a competitive market would. In order to understand how advanced cost

recovery affects the process of consumer protection it is necessary to review several of the key principles of market competition and consumer protection that guide public utility commissions.

Q. Why are the concepts of used and useful important to utility regulation?

A. In traditional utility rate making, the utility makes all the investment in the plant necessary to bring it on line with shareholder resources. When the plant is ready to go on line, the utility seeks to put it into rate base. Only when the plant is ready to deliver electricity is it considered to be "used and useful" to the captive customers of the utility.

In a general rate case, the utility will seek to charge ratepayers for the sum it has invested in the plant, as well as recover the operating (variable) costs of generating power. The sum invested is also allowed to earn a return on capital during the construction phase, which is typically entered into a separate account (allowance for funds used during construction, AFUDC). The rates charged to consumers also include depreciation of the plant as it produces electricity, which returns the capital investment to the utility. Thus the utility gets a return of and on its capital while the plant is operating.

Q. What role does the obligation that rates be just, reasonable and prudent play in utility regulation?

A. The task of public utility commissions is generally to ensure that the utility delivers the least cost power, subject to the need for reliability (and other) considerations, since that would be the outcome in the marketplace. Competition drives the least cost, most efficient technology to the consumer. Emulating a competitive market, the public utility commission will consider whether the costs the utility seeks to recover from ratepayers are "just, reasonable and prudent."

The commission oversees the decision about which technologies to use and which costs utilities are allowed to recover. Even where the construction of new facilities takes place within the parameters of an Integrated Resource Plan, which is a long term energy plan, the fact that the utility has been told or allowed to build a certain type of plant does not alter the fact that the costs cannot be recovered from ratepayers until the plant is used and useful and the cost (including the return on investment) are found to be just, reasonable and prudent.

These two principles of utility regulation protect consumers from different potential abuses. Used and useful ensures that ratepayers receive service in exchange for the recovery of costs, while just, reasonable and prudent ensure that the costs recovered are not excessive.

If projects are cancelled or abandoned they do not become used and useful and their costs would not normally be recovered in the marketplace. If all sellers suffer similar problems, market elasticities of supply and demand will determine the extent to which the costs will be recovered. Under some circumstances utilities may recover the costs associated with abandoned projects, if they can show that the decision to commence the project was prudent and the causes of the termination of the project were not imprudence on the part of the utility.

This pattern of cost recovery reflects what would happen in a competitive market, which is why it is used as a ratemaking standard. When a product is sold to the consumer, the consumer has the immediate use of the product and the price includes only a normal return on investment (if the market is competitive). Suppliers who are inefficient and have costs above the market price or who try to earn above-normal profits by setting prices above costs will not be able to recover those excess costs from consumers. Consumers would not purchase the overpriced products because they would have lower cost options in the market place. The supplier's inefficiency will come out of the supplier's pocket in the form of a lower rate of return

earned on the investment. These principles balance the interest of utility stockholders, who receive a fair rate of return for the risk they take, and ratepayers, who receive useful products at just and reasonable prices.

Q. How does advanced cost recovery alter the process of ratepayer protection?

A. Allowing utilities advanced cost recovery dramatically alters the aforementioned consumer protection process in a number of ways. The utility gets to charge ratepayers before the plant is used and useful. In the case of South Carolina, the recovery of approved costs is guaranteed, even if the reactor is not completed, subject to a prudence review. These changes alter the incentives of the utilities and shift the balance between stockholder and ratepayer interests.

- Advanced cost recovery with a guarantee of recovery shifts the risk of construction so dramatically that it provides a strong incentive for utilities to pursue the technologies that have been favored by the statute.
- By conferring a special advantage on nuclear, it distorts the utility and regulatory decision making process and gives utilities an incentive to choose investments that yield higher, guaranteed returns, even where the investments are not the lowest cost option.
- Shifting the risk of nuclear reactor construction onto the backs of ratepayer creates an ongoing problem because it diminishes the utility's incentive to drive a hard bargain with vendors or joint owners that recovers cost overruns from them, rather than ratepayers.
- Pre-approving and guaranteeing costs creates a large quantity of sunk costs. Utilities can "nickel and dime" the Commission to death with a series of "small" cost overruns, which the commission may feel pressured to approve, since so much has been sunk.

- Because the technologies that tend to be favored by advanced cost recovery are very large central station technologies, utilities favor them, since they increase the rate base and inflate shareholder income.
- Nuclear projects are so large that utility management tends to become totally focused on the single large project and to disregard or resist alternative projects.
- They may even have an incentive to oppose alternatives that might reduce the need for the large central station facilities.

Q. Does this general view of advanced cost recovery fit the South Carolina Base Load Review Act?

A. Yes, it does. On the one hand, the BLRA gave strong incentives for the utility to choose to build nuclear reactors to meet the future need for electricity. The statute gave a utility investing in a new nuclear reactor a remarkably good deal:

- advanced cost recovery,
- no challenge of individual cost elements as imprudent, guaranteed cost recovery as long as the utility adhered to the construction schedule and cost estimates,
- flexible scheduling contingencies,
- an automatic rate of inflation,
- the choice of advanced cost recovery or normal utility cost recovery,
- the full commission approved rate of return, even though substantial risk had been transferred to ratepayers through all of the above mechanisms; and
- allocation of recovery of costs of a base load facility according to peak load demand.

On the other hand, the BLRA did not alter or eliminate many of the features of utility regulation that are intended to protect consumers.

- The definitions of just, reasonable and prudent were not amended.
- The initial decision to build a reactor with advanced cost recovery is subject to the traditional principles that require the costs associated with the project to be just, reasonable and prudent, even though that decision was before the reactor became used and useful.
- Cost increases above the initial level approved to also be subject to full prudence review.
- If a project is abandoned, recovery of costs is subject to prudence review.
- The Integrated Resource Planning (IRP) process was not altered.

Q. Are you asking the Commission to change its approach to the implementation of the just, reasonable and prudent principles?

A. Not at all. The suspension of the used and useful standard for these specific investments introduces distortions into utility decision making that highlight the importance of the just, reasonable and prudent principles for ratemaking. I am only suggesting that the Commission rigorously apply the existing standards when it has the opportunity to do so. The BLRA review of cost overruns is an important opportunity.

Having opened the door to a prudence review under the BLRA by seeking to recover cost overruns from ratepayers, I believe the underlying statute also requires that the cost overrun be considered in the broader context of the overall project. I am not suggesting that the commission look back to disallow any costs that have already been deemed prudent by the initial ruling, but to ask whether further costs should be incurred. The statute allows all costs that have been approved to be recovered, but that does not stop the utility for deciding not to incur additional

costs, if the project is no longer the least cost alternative, nor does it preclude the Commission from examining the new, higher cost of the total project as part of its prudence review of the incremental cost overruns.

IV. THE DRAMATIC CHANGE IN ELECTRICITY RESOURCE COSTS

Q. How have the market conditions changed?

A. The economic fundamentals of the decision to build Summer 2 & 3 have changed so dramatically in just four years that it is imprudent for the utility to continue with the project. To demonstrate the impact of changing circumstances, I focus on the comparison between natural gas and nuclear because that is what the utility focused on in the initial BLRA filing. Showing that the conclusion reached by the utility and accepted by the commission is no longer valid presents the most direct challenge to the prudence of decision making on a going forward basis. I also note in my testimony that the change in circumstances creates the possibility to revisit alternatives like efficiency and renewables.

Q. What has happened to natural gas prices?

The collapse of gas prices has been dramatic, tied to a technological breakthrough in drilling, which has dramatically increased the availability of natural gas.

Exhibit MNC-2 sheds light on this dramatic shift. It reproduces the gas price projection from the 2008 proceeding and overlays the most recent projection from the Energy Information Administration.

Exhibit MNC-3 shows that the EIA projections are consistent with the current futures market. Today one can buy natural gas futures for 2020 delivery at a fraction of the level used in the 2008 analysis. The long run history of natural gas prices shows that the very high prices of the 2005-2008 period when the policy and analysis of nuclear reactors were being written in South Carolina were an aberration, the exception, rather than the rule.

The evidence in the 2008 proceeding calculated the increase in annual cost (calculated as levelized costs, which adjusts for inflation and the time value of money) if natural gas was 25% higher than the baseline, at \$53.4 million per year. The current EIA projection is 62% lower than the baseline. The levelized cost of the natural gas scenario at the current EIA projected costs would be about \$132 million less per year. Since the 2008 baseline natural gas scenario was \$15 million per year higher than nuclear, at current EIA projected prices the natural gas scenario would be over \$115 million per year lower.

Q. Are there other factors that indicate the nuclear option is less attractive compared to gas than it may have seemed in 2008?

A. Yes, there are several. The capital cost of adding natural gas capacity has probably declined relative to nuclear. While the underlying cost escalators for all utility plant construction has declined, the cost overruns for nuclear have taken back all of the reduction in the escalation that could have lowered consumer bills. Since capital costs account for a much smaller share of the total cost for gas plant, the effect is small, but not insignificant.

Q. Did the assumption about a carbon tax play an important role in the 2008 economic analysis?

become more attractive when risk is factored in. The more carefully an IRP considers alternatives, the more attractive efficiency and renewables become.

Q. Is risk analysis generally used in making resource decisions?

A. Yes it is. As discussed above, the centerpiece of the company's 2008 economic analysis was just such an implicit risk assessment. The risk factor they chose to make central was the level and escalation rate of a price on carbon.

V. COST OVERRUNS UNDER THE BLRA

Q. How does the BLRA view cost overruns?

A. In spite of all the remarkably favorable treatments of nuclear reactors under the BLRA, the utility has chosen to leave the safe harbor of the initial prudence review and seek recovery of a massive cost overrun. I believe that it is imprudent within the terms of the advanced cost recovery language of the statute. The statute did not intend to give the utility a blank check. Cost overruns must be just, reasonable and demonstrated to be prudent.

The utility originally sought approval of the project on the basis of a cost estimate and then revised it upward after the contingency cost pool was not allowed. Given the special treatment of costs under the BLRA, cost increases demand close scrutiny, to avoid a strategy in which the utility locks in sunk costs with low-ball estimates and puts pressure on regulators to approve a series of "small" cost overruns.

The fact that the company identifies a series of risks associated with the construction of nuclear reactors did not excuse it from properly evaluating and incorporating those risks into the

initial cost estimate. If they can shift the risks to ratepayers, they will be inclined to make more risky decisions than they would if they had skin in the game.

The fact that the company identifies a series of risks associated with the construction of nuclear reactors does not exempt it from bearing some of the costs of those risks. It earns a full rate of return on its capital, which is supposed to reward it for risk, and has been afforded a variety of other incentives to invest in nuclear.

Q. What costs should have been factored into the original estimate?

A. The excuses the utility gives for the cost overruns are characteristics of the nuclear construction process that are well known and have been recognized for decades. They were identified by analysts of the current building cycle early on. Prudent decision making would have taken these factors into account when the proposal was presented to the Commission. The risks that the utility identifies and now wants to pass on to the ratepayers were well known before they made the cost estimate on which the reactors were approved and before they signed the EPC contract.

- The fact that there would be difficulties in finding adequately qualified and trained personnel was widely recognized.
- The fact that the supply chain was stretched thin was widely recognized.
- The fact that there would be bumps in the road of regulatory approval was also certainly predictable. The failure to comply with NRC requirements is the responsibility of the utility, not the ratepayers or the NRC.

- Given the history of nuclear reactor construction in the U.S. and around the world, the fact that requirements would evolve over time should have been foreseen and included in the cost estimate.

Q. What costs that should not be shifted to ratepayers?

A. The fact that SCG&E hoped others would help to defray the cost of developing a completed design was poor judgment on its part. Its cost estimate should have reflected the possibility that it would need to complete the project on its own. Hoping that five utilities would share the costs of finishing the design work was a risk the utility chose to take. The fact that the vendor apparently scuttled that approach by refusing to allow companies who had not signed an EPC to continue to participate in the design work (by not allowing them to see confidential information), only compounds the imprudence. Here we have a gamble by the utility that went bad as a result of unilateral action by the vendor, perhaps in an attempt to close sales, but the ratepayers are asked to pick up the tab.

The utility has discovered that its information technology (IT) systems are outdated and need to be updated. Unit 1 requires the upgrade, which would be reviewed in a general rate case. Antiquated IT costs are shifted from Unit 1, where they would be subject to routine cost recovery, into the Base Load Review Act proceeding (Walker, p. 15)

Q. Is the allocation of the burden of risk in the cost overruns just, reasonable and prudent?

A. No it is not. The company has shouldered none of the risks. The company points out that it negotiated a reduction in the vendor's claim for additional costs. Compared to the costs that

the utility has asked ratepayers to cover, the utility has asked for ratepayers to pick up six-sevenths of the total cost overruns. The utility has shouldered none of the costs as Table 1 shows:

Table 1: Allocation of cost Overruns

	Change Orders	Owner Cost	Transmission	Total
Vendor	\$76	0	0	76
Ratepayers	\$156	276	21	453
Owner	\$0	0	0	0

Sources and Notes: Total of increases in Order No. 2009-104(A), Exhibit 1 and 2012 requests as outlined in (Testimony of Kevin B. Marsh, pp.8, 9,19)

As my discussion of the role of prudence review above makes clear, producers are likely to bear some or all of the risk of cost overruns in competitive markets. Given that the utility is guaranteed a full rate of return in advance, allowing it to avoid any share of the cost overruns insulates it from the risks that ratepayers and even the vendors are bearing.

Q. On what do you base your claims that many of these risks were known and should have been factored into the original cost projections?

A. I have done extensive analysis of both the long-term history of nuclear construction and the development of the recent nuclear construction proposals. My analysis indicates that every one of the causes of the cost overruns here should have been quite evident to a prudent utility at the outset. The utility charged ahead with a low ball estimate in spite of this clear evidence of risk, underestimating the costs, which it now seeks to recovery through a third bite at the apple.

Exhibit MNC-10 presents a comprehensive view of U.S. nuclear construction cost estimates and actual costs, which I began compiling in 2009 to evaluate the question of whether

nuclear cost escalations are predictable. Versions of this graph have been reprinted in a number of diverse places, with the version in Exhibit MNC-10 drawn from my article in the current issue of the *Bulletin of the Atomic Scientists*.¹⁵ Not only was the tendency for cost escalation known from the first generation of nuclear reactor construction, the recent cost estimates had shown a similar tendency from the beginning of the so called “nuclear renaissance” to 2008 when the utility put forward its cost estimate here. By comparing cost escalation in France and the U.S., as shown in Exhibit MNC-11 and analyzing the fundamental problem that safety poses for nuclear power, I have shown that the cost escalation problem is endemic to the technology.

The fact that there would be particular challenges in restarting a nuclear construction sector in the U.S. was well known at the time the utility prepared its estimate. The Keystone Center's study of nuclear power¹⁶ pointed to “a recent nuclear industry conference that was covered in a February 2007 story in *Nucleonic Week* that ran under the headline “Supply chain Could Slow the Path to Construction” and a January 18, 2007 story that ran under the headline “Vendors Relative Risk Rising in New Nuclear Power Market,” in regard to labor shortages.

By rushing to be among the first in line, for a design that had not been approved or implemented in the U.S., the utility took on extraordinary risk, that it failed to include in its initial cost estimate. It now seeks to impose the costs of its imprudently rosy initial cost projection with approval of cost overruns. If more than \$450 million of cost overruns had been included in the initial cost estimate, the Commission might well have concluded that nuclear reactor construction was not just, reasonable and prudent, even with the assumptions about high gas and carbon costs.

¹⁵ Mark Cooper, “Nuclear Safety and Affordable Reactors: Can We Have Both?,” *Bulletin of the Atomic Scientists*, 68(2), 2012, p. 63.

¹⁶ The Keystone Center, Nuclear Power Joint Fact-Finding, June 2007, p. 33.

Subsidizing the revival of the nuclear construction sector was not the intention of the BLRA. The project must be just, reasonable and prudent by the traditional standards and the utility was obligated to factor those risks into its initial cost projection.

Q. Is the imprudence of nuclear construction recognized in the utility sector?

A. Yes. Ironically, the three utilities that the vendor blocked from working on the completion of the design were excluded because they had decided not to sign an EPC and move ahead with construction. In fact, the vast majority of projects that were under consideration when SCE&G signed its EPC have been cancelled or are dormant. SCE&G's public sector partners have been reducing their take of power from the project at a rapid pace.¹⁷ General Electric, one of the largest vendors of generation technologies with a broad portfolio of wind, gas and nuclear has concluded that nuclear is much less attractive than gas and wind.¹⁸ The EIA, Exelon and PJM analyses reach a similar conclusion, as do a number of other regulatory bodies and Wall Street analysts.¹⁹

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

¹⁷ <http://www.santeecoopergreen.com/portal/page/portal/santeecooper/aboutus/newsroom/santeecoopernewsreleases/25539444.pdf>; <http://www.businesswire.com/news/home/20120327006867/en/Fitch-Rates-South-Carolina-Public-Service-Auths>; <http://www.columbiabusinessreport.com/news/42877-duce-energy-moving-ahead-to-buy-stake-in-v-c-summer-nuclear-station>; <https://www.santeecooper.com/portal/page/portal/santeecooper/aboutus/newsroom/santeecoopernewsreleases/bd9094aabb8529bde044001a4b08f969>; http://nuclearstreet.com/nuclear_power_industry_news/b/nuclear_power_news/archive/2012/04/23/santee-cooper-signs-letter-of-intent-with-american-municipal-for-v-c-summer-reactors-042502.aspx;

¹⁸ <http://www.ft.com/intl/cms/s/0/bd975d10-dd59-11e1-8fde-00144feab49a.html#axzz22xSbueX4>.

¹⁹ In addition to the California Energy Commission cited above in not 18, Mark Cooper, *The Economics of Nuclear Reactors: Renaissance of Relapse*, Institute for Energy and the Environment, Vermont Law School, June 2009, Chapter 5 discusses various estimates.

1 **BEFORE THE**
2 **SOUTH CAROLINA PUBLIC SERVICE COMMISSION**
3 **SURREBUTTAL TESTIMONY**
4 **OF**
5 **DR.MARK COOPER**
6 **ON BEHALF OF THE SIERRA CLUB**
7 **DOCKET NO. 2012-203-E**
8

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COMMISSION

9 **Q. Please state your name and address.**

10 **A. My name is Dr. Mark Cooper. I reside at 504 Highgate Terrace, Silver Spring, Maryland.**
11

12 **Q. Are you the same Mark Cooper who is providing direct testimony in this**
13 **proceeding?**

14 **A. Yes, I am.**
15

16 **Q. What is the purpose of your surrebuttal testimony?**

17 **A. My testimony responds to the rebuttal testimony of the company witnesses, showing that**
18 **they have misrepresented my analysis and recommendations and failed to provide the**
19 **Commission with any evidence that it is prudent to continue incurring costs for the V.C. Summer**
20 **units 2 & 3.**
21

22 **Q. Do you agree with Company witness Byrne's the claim (p. 1)¹ that your testimony**
23 **has several inaccuracies and misunderstandings?**

¹ All page references are to the Company witness rebuttal testimony, unless otherwise noted.

1 **A.** Yes. The company objects to my characterization of the EPC as a rush to judgment by
2 citing its reporting on the progress of the project. The cost overruns that the company is seeking
3 to recover from ratepayers is one clear indication that the project is not humming along. The
4 cost overruns are the result of rushing to get at the head of the line.

5 The primary rationale for signing the EPC early offered in the risk assessment that Mr.
6 Byrne attaches to his rebuttal testimony has evaporated as the bubble of the nuclear renaissance
7 burst. Rather than a rush of orders (p. 1, 3, 6), which the utility considered a threat to increase
8 costs, there has been a mass abandonment of projects, including the reference design project
9 (p.2). Design revisions have increased by almost one third (p. 2). Licensing has been delayed
10 because of substantive design problems (p. 3-4). The availability of qualified personnel has
11 clearly been a problem (p. 6), as have manufacturing and quality issues (p. 7). The collaborative
12 effort to defray the cost of completing the design has collapsed. These are the difficulties that
13 have led to an increase in the cost estimate. Being first in line will cost ratepayers dearly. Given
14 the collapse of the nuclear renaissance, if anyone were ordering new reactors toady, they might
15 get a lower cost because demand is so slack and the early reactors have borne the brunt of the
16 learning costs, but the economics of new nuclear construction has turned so sour that new orders
17 are not being placed.

18

19 **Q.** What does the company rebuttal show about the prudence of passing through the
20 cost overruns requested in this proceeding?

21 **A.** One thing the company rebuttal testimony makes abundantly clear is that the company
22 has failed and refuses to ask the key question that must be asked – is the project still prudent
23 going forward?

1 Presenting quarterly reports that show progress down a chosen path is not the analysis
2 that is needed to ensure that the utility is acting prudently. This is exactly the myopic tunnel
3 vision thinking that preapproval and advanced cost recovery creates. Management must raise its
4 eyes up and look at the landscape not just keep plowing ahead.

5 The rebuttal testimony points back to the 2008 analysis of options (March, p. 4, Lynch
6 12), but with massive changes in a host of material facts that affect the economic situation, that
7 will not do, as I showed in my direct testimony.

8 The company witnesses admit that they have not calculated the costs of terminating the
9 EPC contract. Byrne 13-14, says the cost "could be material." The utility should know and the
10 Commission needs to know what they are, so they can be compared to the cost savings that
11 would result from switching to less costly ways to meet the need for electricity. With three
12 quarters of the costs yet to be incurred, now is the moment to have a full review of the prudence
13 of the project.

14 The company response to my calculation of the change in natural gas costs and the
15 current landscape with respect to carbon policy is to suggest that adjustments to the nuclear cost
16 estimates would offset my adjustments to the natural gas cost estimate (Lynch, p. 11-12). In my
17 opinion they have botched and misrepresented the comparison, but the important point is that the
18 Commission needs a new economic analysis of the going forward costs to ascertain whether
19 continuing the project is prudent. The company has not provided that analysis.

20 Given the history of the industry and the nature of the risk the project faced, the company
21 did a poor job of estimating costs, which is why it has come back in for approval of two major
22 cost overruns. I believe that many of those overrun costs should have been anticipated and
23 included in the original cost projection and should, therefore, not be recovered from ratepayers.

1 Even if it could be demonstrated that each of the individual costs increases is necessary
2 for the execution of the project, that is all the more reason to re-examine the prudence of the
3 project itself. If the company had properly reflected the risks in its initial cost estimate, the
4 Commission might well have found it not prudent in the first place. Given the statute, the sunk
5 costs must be recovered, but with three-quarters of the costs not yet incurred and in the face of a
6 second major cost overrun, now is the time to re-examine the prudence of the project itself.

7

8 **Q. Why do you say the company has botched and misrepresented the comparison?**

9 **A.**There are two reasons. First, in my testimony I pointed out that my analysis was based
10 only on fuel and carbon cost differences. I noted that the reduction in escalation as a result of
11 general economic conditions would apply to non-fuel costs for the gas plant. The company
12 projects a significant reduction in those non-fuel costs of nuclear construction and compares that
13 to my estimated natural gas fuel cost savings. The company points out that fuel costs are a larger
14 part of total gas costs than fuel costs are of nuclear. However, the company's own estimate
15 shows that non-fuel costs are still important in the total gas cost. For nuclear, fuel costs are 13%
16 of total costs, while for gas fuel is 41% of gas costs (Marsh, p. 7). If we assume that the non-fuel
17 component of gas generation has enjoyed a similar reduction due to the general economic
18 conditions, the proportionate reduction in revenue requirement for the non-fuel component
19 would be about \$200 million, as described in Attachment MNC-SR-1. Combining the fuel and
20 non-fuel cost savings from natural gas, compared to nuclear, gas would still beat nuclear by a
21 wide margin. The economic advantage of gas could more than offset the sunk costs that the
22 utility is allowed to recover, leaving the ratepayers better off as a result of the decision to
23 abandon the project.

1 September 2, 2012). The deal is short term, but it does demonstrate the immense advantage that
2 natural gas fired generation has compared to the embedded cost of generation, not to mention the
3 much higher costs of new nuclear reactors.

4 In my opinion the cost advantage of natural gas would be more than adequate to
5 compensate for the sunk costs of this nuclear project that must be borne. The rebuttal and
6 surrebuttal testimony make it all the more urgent that the Commission require the company to do
7 a complete, bottom-up cost analysis before these cost overruns are approved and more costs are
8 sunk in a project that is totally uneconomic in the conditions of today's market.

9
10 **Q. How do you respond to the company's claim that the cost of the reactor has gone**
11 **down?**

12 **A. I have two responses.**

13 First, the company is playing a game of "heads I win, tails you lose" with ratepayers. If
14 escalation pushes costs up, the ratepayers pay. If escalation lowers costs, the company finds
15 excuses to keep the money. Ratepayers are paying more than they should for the reactor.

16 Second, the cost of gas has gone down a lot more, so ratepayers are paying too much for
17 the wrong technology.

18
19 **Q. Is the criticism of your discussion of alternatives correct?**

20 **A. No. The claim that my view of natural gas contradicts that of the Sierra Club is wrong**
21 **for two reasons.**

22 First, natural gas is the alternative the company chose as the base case. I have accepted it
23 and shown that on the company's own terms, the choice of nuclear is not prudent today.

1 Demonstrating that current conditions lead to the conclusion that nuclear is not the preferred
2 option on the company's own terms is the first step in demonstrating that a careful and thorough
3 prudence review is necessary. I made it clear in my testimony that it is not the last step.

4 Second, the company has leapt from my demonstration that gas beats nuclear to the
5 conclusion that I believe gas is the right choice. They combine this erroneous assumption with
6 the observation that my clients in this case have expressed concerns about natural gas to claim
7 that there is an inconsistency between my position and theirs. Nothing could be farther from the
8 truth. This is another example of the failure of the company to do careful analysis of the facts.

9 Exhibits MNC SR-3 and SR-4 show the results of two recent analyses I have presented
10 where I apply a multi-criteria approach to a full range of over a dozen alternatives. I conclude
11 that there are several alternatives that are superior to gas. This is based on national average data.
12 I believe such an analysis should be conducted in the thorough prudence review that Commission
13 orders in this proceeding.

14 Moreover, a review of the Sierra Club's published "Energy Resource Policy" cited by the
15 company's witness Marsh, confirms that the Club's policy position is fully consistent with my
16 analysis.

17 The text accompanying my Exhibit MNC SR-3 reads as follows:

18 Adding the analysis of vagueness to risk and uncertainty as in [the] Exhibit...
19 changes the rankings of several of the resources somewhat although the basic
20 conclusion stands. Efficiency is the most attractive by far. Wind, landfill, hydro
21 and geothermal are also more attractive than gas." (Mark Cooper, "Prudent
22 Resource Acquisition in a Complex Decision Making Environment:
23 Multidimensional Analysis Highlights the Superiority of Efficiency, Current
24 Approaches to Integrated Resource Planning," *2011 ACEEE National Conference*
25 *on Energy Efficiency as a Resource*, Denver, September 26, 2011)
26

27 The text accompanying Exhibit MNC SR-4, reads as follows:

1 [The] Exhibit...combines the 'new' ambiguity scale with the traditional core of
 2 utility regulation – levelized cost to identify the best path to the future. The route
 3 is clear. It begins with efficiency, wind and a mix of other renewables, with gas
 4 as a complement. It can then proceed on one of two paths, a renewable route that
 5 goes through solar and offshore wind, or a fossil fuel path that includes carbon
 6 capture and storage. Nuclear is the most unattractive of the resources. (Mark
 7 Cooper, "Least-Cost Planning For 21st Century Electricity Supply: Meeting the
 8 Challenges of Complexity and Ambiguity in Decision Making," *MARC Annual*
 9 *Meeting*, Rapid City South Dakota, June, 2011)

10 I have expressed concerns about a second dash to gas for exactly the same reasons that
 11 the Sierra Club is concerned about it: it undermines and delays the development of more
 12 important alternatives on which the electricity sector will inevitably rely. I believe that slowing
 13 and delaying the transition away from fossil fuels will raise the ultimate cost of transforming the
 14 electricity sector into an efficient, clean 21st century sector. Looking out over the long term to
 15 2050, as shown in Exhibit MNC-SR-5, my base case to achieve the goal of carbon reduction did
 16 not include gas. I did note its potential role as a complement, but I emphasized the need to
 17 develop the alternatives. The text accompanying Exhibit MNC-SR-5 reads as follows.

18 [The] Figure... combines these and several other estimates for efficiency and
 19 renewables, using the costs discussed earlier into a "supply" curve. It expresses
 20 the quantity of low carbon supply in two forms – billions of kWh and as a
 21 percentage of the base case demand in 2050. The 2050 base case demand is
 22 projected from the most recent Energy Information Administration projection of
 23 demand in 2030 by assuming the same underlying growth rate of demand from
 24 2030 to 2050 as EIA assumed between 2010 and 2030. This calculation assumes
 25 that all existing low carbon sources of electricity must be replaced in the long-
 26 term. In other words, by 2050 there will be an entirely new set of resources
 27 meeting the need for electricity, none of which is online today.

28 [The] Figure... also shows a case with natural gas assumed to be needed to be
 29 integrated with low load factor renewables (wind and solar) on a one-for-one
 30 basis. This may not be necessary until higher levels of contribution from wind and
 31 solar are reached. Other options, particularly new storage technologies, may also
 32 fill this need to balance out low load factor renewables. Nevertheless, the quantity
 33 of gas needed to play the balancing role in the alternative supply curve is well
 34 within the range of EIA gas projections for 2030, especially when one considers
 35 that efficiency will free up a significant quantity of gas for other uses.
 36
 37

1 **MR. GUILD:** Mr. Commission, if the Commission
2 please, and Mr. Zeigler would like, it would be
3 appropriate now to take a break and have him come
4 back to speak about his supplemental surrebuttal
5 testimony, at that point.

6 **CHAIRMAN WRIGHT:** Do you still need it?

7 **MR. ZEIGLER:** Mr. Chairman, I think we can
8 move forward with the supplemental surrebuttal.
9 I've had a chance to look at it.

10 **MR. GUILD:** All right. Thank you.

11 **BY MR. GUILD:**

12 **Q** Dr. Cooper, then, as you acknowledged that since you
13 received the supplemental exhibit from Dr. Lynch, the
14 comparative analysis, last Thursday, the data request
15 over the weekend, you had occasion to prepare
16 supplemental surrebuttal testimony responding to that
17 comparative analysis; isn't that right?

18 **A** Yes.

19 **Q** Do you have a copy of that document before you?

20 **A** Yes, I do.

21 **MR. GUILD:** I have to apologize for not having
22 extra copies to begin with, for the Commission, but
23 I understand the Commissioners have it now. All
24 right.

25 <

1 that are contained in the balance of this document, this
2 surrebuttal testimony, were asked today, would your
3 answers be the same?

4 A Yes, they would.

5 MR. GUILD: With that said, Mr. Chairman, I
6 would ask that the document, surrebuttal testimony
7 of Dr. Mark Cooper, be accepted into the record as
8 if read.

9 CHAIRMAN WRIGHT: The supplemental surrebuttal
10 testimony of Dr. Cooper will be entered into the
11 record as if read orally from the stand.

12 [See pgs 1001-1011]

13 MR. GUILD: All right.

14 BY MR. GUILD:

15 Q And, Dr. Cooper, would you summarize that surrebuttal
16 testimony?

17 A Okay. Well, again, there are six major points I wanted
18 to make and then I'll put up one slide. If you read the
19 analysis and if you listen to Dr. Lynch, there's a
20 critical assumption in their analysis and their approach
21 that the way to decarbonize the US economy and the
22 electricity sector is to impose a large direct tax on
23 carbon, and he says you could have a tax, you could have
24 a cap-and-trade which is like a tax, and then he says
25 you could have standards. It turns out, it makes a big

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1 difference. Standards are not taxes. And so when the
2 EPA issued a series of rules that basically make it very
3 expensive to build coal, they don't put a tax on gas.
4 And that's a big difference.

5 It turns out there's growing literature in the
6 economic literature, looking at the challenge of
7 decarbonization, which actually concludes that price is
8 not the best way to do this. It's not the most
9 efficient policy tool. You get better reaction, you do
10 less wealth transfer, less economic dislocation, if you
11 target technologies with incentives and disincentives,
12 like standards. And so that fundamental difference of
13 opinion can let me be for decarbonization but not a big
14 fan of taxes.

15 And if you'll read the rebuttal testimony, they
16 made a big deal of that, that I was a gas guy, and I --
17 and the simple fact of the matter is that the efficient
18 way to do this -- and lots of people are figuring that
19 out, and that's what Waxman-Markey was about. Remember
20 that bill. It was more about a 20 percent reduction in
21 consumption, and renewables, than it was about that
22 carbon tax. So that is changing. First -- that's the
23 first assumption that's -- and that's actually the
24 second assumption.

25 So as a policy matter, the reality on the ground

1 today is, we don't have a carbon tax. But we do have a
2 decarbonization policy, certainly, in Washington. It's
3 growing. We have this EIA -- EPA's coal standards. We
4 have appliance efficiency standards up 20 to 25 percent,
5 so your air conditioners in 15 years are going to burn a
6 lot less electricity. We have a fuel economy standard
7 that doubled the fuel economy of automobiles by 2025.
8 So we do have a decarbonization strategy emerging. It
9 snuck up on everybody -- and maybe that's the only way
10 to get it. But it doesn't have a tax. So the policy
11 reality is different.

12 The third, and in this study they only look at gas
13 and nuclear. This study does not comprehensively bring
14 in all the alternatives in this proceeding where -- this
15 is where the money is. The IRP is an important
16 proceeding, but this is where the money is, and it
17 doesn't bring in all those alternatives and look at the
18 potentials.

19 So those are the big conceptual questions. It
20 doesn't include the low cost of other alternatives. It
21 assumes that there is no future risk in nuclear costs.
22 Let's be clear. We've learned a tremendous amount about
23 it, and now we say it's minimal, but none of the company
24 witnesses say they're willing to guarantee, and they
25 don't use any range of price projections for nuclear.

1 So it's a risk-free cost in that analysis. That seems
2 to me to be unacceptable.

3 It also assumes this rigid construction schedule,
4 and gas is more flexible than nuclear. You've heard
5 units from 458 to 800. People model combined-cycles
6 from 400 to 800. You can add a peaker if it avoids
7 excess capacity.

8 And so all of these differences, I believe, distort
9 that analysis. And so I want to reach a different
10 conclusion. And I've done a lot of data, but -- if we
11 can advance that one.

12 [Reference: Cooper Presentation Pg 7]

13 And so what I have done here is take a series --
14 taking their base-case assumption, and if you look at
15 the analysis -- if you look at the analysis they gave
16 me, if you look at the responses to interrogatories, the
17 base-case assumption that represents the reality that
18 this Commission must start from is zero carbon cost.
19 That's the world you live in. Some of us would like it
20 to be a big tax. There is no carbon tax today. The
21 base-load projection for demand and the base-load
22 projection for gas. That's the starting point. We can
23 do all kinds of -- he called them sensitivity analyses,
24 and that is, I think, a fair way to describe them. He
25 did not do scenario analyses, where we think about --

1 where we vary the assumptions that I talked about.

2 So what I've done here is I have done two things.
3 One, if you look at that base case -- zero carbon-tax
4 base load -- the two choices are almost identical. \$26
5 million in levelized annual costs, on a levelized annual
6 cost stream of \$2 billion. Less -- a little over 1
7 percent. That's the \$26 million number. And, of
8 course, that \$26 million number is driven entirely by
9 the sunk costs. So I separate out here economic costs,
10 which are the going-forward costs, and the sunk costs
11 which economists say you should never look at. It turns
12 out humans have trouble with that, but economists don't.

13 So what happens is that there is a dead heat, even
14 with those sunk costs heaped on. And now I say, let's
15 -- I call them sensible scenarios. Someone called them
16 reasonable this morning. I had to find a different
17 word. Let's amortize over a much shorter period. I
18 think that lowers the revenue requirement, because I
19 assumed that the company was earning profit on that \$2.4
20 billion as long as it's being amortized. That is, they
21 didn't give up their claim to profit, so it's my
22 experience -- and Mr. Guild talked about all these cases
23 where consumer advocates fought to shorten the period,
24 because it reduced the total revenue requirement. So
25 I've shortened the period. And again, this is

1 preliminary, since we didn't have much time. I've got a
2 ten-year straight-line depreciation with an 8.4 percent
3 return, and you dramatically reduce the revenue
4 requirement, which tips the outcome in favor of gas.
5 This is one scenario.

6 If you then -- I want to look at a flexible build,
7 because I show in my testimony you can move gas out if
8 you use a 14 percent reserve requirement; you don't have
9 to add it as quickly. And that has the same effect.
10 You put these two together, gas beats the bejesus out of
11 nuclear.

12 And now, this is a going-forward analysis, but I
13 want to make a point here that this is the reality of
14 your neighbors who haven't sunk their costs into a
15 nuclear project. This is why all the utility executives
16 have abandoned, why Santee Cooper wants to get out,
17 because if they didn't get in too far, they look and
18 say, "Wait a minute, that's the wrong route," and I
19 think those [indicating] are the reasons why.

20 I did another scenario here, which looked at --
21 added the 10 percent to nuclear. And at one level, Mr.
22 Lynch is right; it doesn't make a big difference, but it
23 makes some difference. But to contrast the 10 percent
24 overrun for nuclear, I contrasted that to his high-gas-
25 cost case, which doubles the price of gas. But, of

1 course, I did my sensible scenario. Gas wins again.

2 My point is that, this is a moment -- as I said in
3 my testimony -- when we can make this decision. It's in
4 the balance. It's close [indicating]. And this moment
5 requires that rigorous, multiple-scenario, multiple-
6 sensitivity analysis which asks all of these questions,
7 and that -- and I think the way to get that done is to
8 deny the 283 and tell the company to do its homework. I
9 personally would have suggested that, if they had done
10 this in 2010, it would have been a no-brainer for
11 cancellation. But I can't. The Base Load Review Act
12 has said I have to go forward. So now is the moment to
13 really do that analysis and make sure that this is the
14 least-cost way to be both environment friendly and
15 consumer friendly, and it all fits under the Base Load
16 Review Act. Make no mistake about it. The Base Load
17 Review Act was that safe harbor that left a lot of
18 consumer protection. It may actually be stronger than
19 Duke realizes, particular because of the Supreme Court
20 ruling that said you don't get unspecified costs.

21 So I think that this is the moment, and that's the
22 key recommendation of my testimony. Thank you.

23 [PURSUANT TO STIPULATION, THE

24 SUPPLEMENTAL SURREBUTTAL TESTIMONY OF

25 MARK N. COOPER, Ph.D., FOLLOWS AT PGS 1001-1011]

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PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1 **BEFORE THE**
2 **SOUTH CAROLINA PUBLIC SERVICE COMMISSION**
3 **SURREBUTTAL TESTIMONY**
4 **OF**
5 **DR.MARK COOPER**
6 **ON BEHALF OF THE SIERRA CLUB**
7 **DOCKET NO. 2012-203-E**

8 **Q. Please state your name and address.**

9 **A. My name is Dr. Mark Cooper. I reside at 504 Highgate Terrace, Silver Spring, Maryland.**

10

11 **Q. Are you the same Mark Cooper who is providing direct testimony in this**
12 **proceeding?**

13 **A. Yes, I am.**

14

15 **Q. What is the purpose of this testimony?**

16 **A. South Carolina Electric and Gas (SCE&G or the company) has introduced an eleventh hour**
17 **report entitled *Comparative Economic Analysis of Completing construction or Pursuing a Gas Resource Strategy***
18 **as a proposed supplemental exhibit to the testimony of Joseph M. Lynch in its petition to collect**
19 **cost overruns of \$283 million for the construction of the Summer 2 & 3 nuclear reactor.¹ That**
20 **analysis purports to show the prudence of continuing the construction of two additional nuclear**
21 **reactors by updating the flawed analysis presented to the Commission four years ago. This testimony**
22 **responds to that filing.**

23

¹Letter to docket No. 2012-203-E, September 27, 2012

1 long-lived asset that requires a long lead time is exactly the wrong strategy in an uncertain
2 environment.⁴

3 By focusing on only two options, nuclear and gas, the company ignores a host of
4 alternatives that are preferable to both. These are the very alternatives that economic theory, policy
5 reality and portfolio management practice indicate are preferable. Excluding all the other options
6 dooms the analysis to fail as the basis of a SCPSC decision.

7
8 **Q. What are the Empirical Problems in the Analysis?**

9
10 The empirical analysis is fundamentally flawed because it excludes from consideration the
11 most important variables.

- 12 • Low cost alternatives, other than gas are not considered.
- 13 • The construction costs of nuclear reactors is fixed at an unrealistically low level,
- 14 • The construction costs of natural gas are fixed at an unrealistically high level.

15
16 **Q. What is the impact of failing to consider all the options?**

17 The myopia that afflicts the SCE&G's analysis is highlighted by the fact that the SCE&G
18 study points out that an Exhibit introduced in the cost overrun proceeding from Exelon, which is
19 the nation's largest nuclear utility has a reference to "projected long run CO₂ price" that puts the social
20 cost of carbon at \$40 per ton of CO₂, as shown in Exhibit MNC-R-2- 1. The SCE&G study ignores
21 the fact that the very same exhibit identifies efficiency and natural gas as lower in cost in addition to

⁴ Mark Cooper, *Least-Cost Planning For 21st Century Electricity Supply Meeting The Challenges Of Complexity And Ambiguity In Decision Making*, Mid-America Regulatory Conference, Rapid City South Dakota, June 2011., p. 51. "The big picture conclusion of this analysis is that the affinity for large base load facilities is a relic of a past that involved much less ambiguity. The prudence of that affinity has been contested for at least a quarter of a century, but this analysis shows the debate should be over. The very characteristics that made central station facilities attractive in an environment with much less ambiguity makes them singularly unattractive in the current environment. Acquisition of central station facilities, particularly nuclear, makes long-term commitments in exactly the wrong way for the current decision making environment. It commits to assets that have high risk (e.g. fossil fuel facilities) or create large exposure to uncertainty (large size, high capital cost, or long lead times) with technologies that have vague long-term prospects (unstable resource availability and poorly understood environmental impacts). As a result, it is no longer acceptable for the bias in favor of large central station facilities to dominate resource planning."

1 wind which is lower in cost with technology specific incentives. The same is true for the supply
2 curve in the PJPM region, which was also included in the original exhibit. Exhibit MNC-R-2- 1
3 shows these two estimates of the "supply curve of for carbon emission" reductions in the electricity
4 sector.

5 The quantity of low carbon supplies available from these lower cost alternatives vastly
6 exceeds the quantity from nuclear reactors. The lesson of these supply-curve analyses is not only
7 that that carbon has a substantial social cost, but also, and perhaps more importantly, that society
8 has a number of low cost options to use to reduce carbon omissions. That is the lesson that
9 SCE&G has failed to learn and incorporate in its analysis. To be sure, these are estimates of the cost
10 of carbon reduction from other utilities and the Commission must base its decision on costs that are
11 specific to South Carolina. This is what the Company refuses to present the Commission in this
12 proceeding. Without that analysis, its action cannot be judged to be prudent.

13 Moreover, the full implications of Exhibit MNC-R-2- 1 must be recognized. The figure
14 shows that a number of important alternatives, especially efficiency and natural gas have declined in
15 cost and/or increased their ability to contribute to the reduction of carbon emissions. Note also
16 that the efficiency options are shown as having a negative cost per ton of carbon reduced. This
17 simply means that the cost of adding these options to the resource mix is less than the current
18 average cost of resources. In other words, adding these resources lowers the average cost while
19 reducing carbon emissions. No matter what climate policy is adopted, many of the resources
20 depicted on this supply curve should be adopted first because they lower the cost of electricity.

21 Leading utility executives are not the only ones who have recognized that the supply curve
22 of electricity includes a number of low cost options that are substantially less costly than nuclear and
23 gas. As shown in Exhibit MNC-R-2- 2, analysts on Wall Street, the California Energy Commission
24 and the Energy Information Administration, provide similar supply curves. The figure presents the

1 projected cost of each resource as a percentage of the projected cost of nuclear power within the
2 study. This controls for different assumptions across the studies and keeps the comparisons on an
3 apples-to-apples basis. There are many options that are less costly than both nuclear and gas. The
4 failure to recognize the facts on the ground that are widely acknowledged by other decision makers
5 is the touchstone of imprudence.

6

7 **Q. Have these alternatives been recognized for some time?**

8 **A.** Yes, as attachments MNC-R-3 shows, by 2010 the view of the alternatives had shifted
9 dramatically. The quantity of low carbon resources projected had increased substantially.
10 Attachment MNC-R-4 shows that gas prices had plummeted dramatically by 2010.

11

12 **Q. What is the Impact of the Failure to Reflect the Riskiness of Nuclear Construction**
13 **Cost in the Prudence Analysis?**

14 **A.** A second egregious empirical flaw in the SCE&G prudence analysis is the failure to consider
15 a range of costs for completing the reactors. The company has gone to great pains to warn the
16 Commission that this is a high risk undertaking. In only four years, those risks have raised the basic
17 cost estimate by 10 percent. The construction phase, which has historically been the most
18 challenging in terms of cost overruns, has only begun. With the economy coming out of the
19 recession, the downward trend of escalation is also likely to be reversed, if inflation is sparked by
20 economic recovery. Inexplicably and in direct contrast to its own risk analysis, the company treats
21 nuclear costs as though they were a certainty and fails to consider future cost overruns or increases
22 in escalation. This could add billions to the nuclear scenario revenue requirement. A twenty percent
23 increase in the construction cost could tip more than half the scenarios considered by SCE&G in
24 favor of natural gas.

1

2 **Q. What is the impact of failure to recognize the value of more flexible alternatives?**

3 A. The third major flaw in the empirical analysis is the failure to realistically analyze the impact
4 of declining or lower growth of demand. The company sets the supply curve in stone, by adding the
5 two nuclear reactors and then assuming that natural gas capacity will be added in exactly the same
6 amount at exactly the same time. However, natural gas can be added in smaller increments and with
7 shorter lead times. By freezing the supply side, the company analysis renders the demand-side
8 analysis and the dispatch modeling irrelevant. Holding capacity constant, with varying demand only
9 allows the modeler to alter the variable (operating costs) in response to changes in demand. There
10 can be no variation in capital costs. An intelligent system designer would reduce capital
11 expenditures if possible. A million PROSYM runs cannot give the right answer because it has not
12 been allowed to ask the right questions.

13 Exhibit MNC-R-2-5 shows the impact of lifting the unwarranted assumption that gas plants
14 must be added in the same year as the nuclear reactors. It assumes a 14% reserve margin
15 requirement, which is a level that occurs in several of the years analyzed, without triggering a
16 decision to add capacity.

17 Under the 14% reserve margin assumption, in the base case, SCE&G could delay adding the
18 second combined cycle gas facility and would have flexibility to choose when to add the second
19 combined cycle plant or peakers. In the low demand scenario offered by the company (i.e. 95% of
20 base case demand) the first gas combined cycle unit is moved back a year, the second gas combined
21 cycle unit is never needed, and the need for three of the four peakers can be eliminated. Modeling
22 the benefits of demand reduction and natural gas flexibility could lower the capital requirements and
23 costs in the gas scenario. Moreover, if larger reduction in the need for non-renewable capacity

1 occur, the importance of incorporating the value of flexibility in supply becomes even more
2 important.

3 For example, if projections of likely climate policy are going to be included in the analysis,
4 then the most likely place to start should be the one bill that came closest to being enacted – HR
5 2454, the Waxman Markey bill that passed the U.S. House of Representatives in 2009. It reflected
6 the much more nuanced approach that focuses on target policies and technology with the goal of
7 lowering demand for nonrenewable generation resources. It could do so significantly. Exhibit
8 MNC-R-2- 6 shows the impact of a reduction in demand for non-renewable resources equal to 10
9 percent and 20 percent of the baseline projection of capacity needed that would result from
10 efficiency and renewables mandated by HR 2454.⁴ Again, I assume a 14% reserve margin
11 requirement

12 If the reactors are completed and policy that mandates efficiency and renewables is adopted
13 (FED), then South Carolina will have a massive amount of overpriced low carbon resources. The

⁴ Direct testimony of Dr. Mark Cooper on behalf of the Southern Alliance for Clean Energy, In re: Nuclear Plant Cost Recovery Clause, before the Florida Public Service Commission Docket no. 090009-EI, July 15, 2009, pp. 20-21, explained these two levels as follows. "On a national average basis, the EPA projects a 10 percent reduction in demand and growth in renewables equal to 1.1 percent of demand (EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress, 6/23/09, p. 26). An earlier analysis suggests the weatherization program in the American Recovery and Reinvestment Act would lower demand by 1.4 percent (Contrast EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress, 6/23/09, p. 26, with EPA Preliminary Analysis of the Waxman Markey Discussion Draft: American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress, 4/20/09, p. 23). The former includes the effect of the ARRA in the reference case, the latter does not. I attribute the difference to the ARRA). The impact varies from state-to-state, however. The American Council for an Energy Efficient Economy estimated the impact of the improvement in building codes and appliance standards in Florida would be 20 percent above the national average (Energy Savings from Codes and Standards Count Towards EERS Savings Goals, available at http://www.aceee.org/energy_efficiency/EERS_savings_goals.pdf). In a state where so much efficiency is available at less than 2.5 cents per KWh, it would make sense to petition for the maximum efficiency contribution to the RIES (8 percent) and develop as much renewable energy as is economic, before sending money to California, Washington, Minnesota and Massachusetts. Combining these factors, a reasonable range for the impact on South Carolina would be a 10 to 20 percent reduction in the demand for non-renewable generation (The American Council for an Energy Efficient Economy puts the savings from Title I and Title II of HR2454 at 5.4 quads in 2020 and 12.2 quads in 2030. These savings work out to 12.2 percent of the energy consumed in the electricity sector in 2020 and 25.6 percent of the energy consumed in 2030 (see HR. 2454 Addresses Climate Change Through a Wide Variety of Energy Efficiency Measures, available at http://www.aceee.org/energy_efficiency/HR2454_Estimates06_01.pdf))."

1 else?

2 COMMISSIONER HAMILTON: Mr. Chairman.

3 CHAIRMAN WRIGHT: Commissioner Hamilton.

4 EXAMINATION

5 BY COMMISSIONER HAMILTON:

6 Q Dr. Cooper, happy to have you with us, and I hope you
7 make your -- I'll be very brief, and hopefully you can
8 make that flight. But we've talked about -- and you
9 talked earlier when you came up, you explained to us
10 with your rebuttal testimony that you're not a gas guy.
11 But you want a carbon-free world. And the fact that you
12 put gas third in line, but it emits half the carbon of
13 coal. In your scenario, nuclear has no place
14 whatsoever, which is carbon free?

15 A Well, no -- look, I'm not anti-nuke. I basically have
16 30 years as a consumer advocate. I used to testify for
17 the Office of the Consumer Advocate.

18 Q I can see a little.

19 [Laughter]

20 A There may be a moment when nuclear comes back into the
21 supply. But that moment, if you look at this supply
22 curve, that moment is out in the 2030s. If you look at
23 Waxman-Markey, that was -- it was way out. I believe
24 there's sufficient potential here in South Carolina to
25 make that decision at the right time. Right now, it's

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1 **VICE CHAIRMAN MITCHELL:** He ought to get a
2 police escort.

3 **MR. GUILD:** May we take just a moment, Mr.
4 Chairman?

5 **CHAIRMAN WRIGHT:** You may be excused.

6 **WITNESS:** Thank you.

7 [WHEREUPON, the witness was excused.]

8 **CHAIRMAN WRIGHT:** All right. At this time,
9 we're going to take about a ten-minute break, so we
10 can get set up for the panel. We'll come back at
11 five after [5:05].

12 [WHEREUPON, a recess was taken from 4:55
13 to 5:10 p.m.]

14 **CHAIRMAN WRIGHT:** Be seated please. We will
15 reconvene the hearing, and turn it over to you.

16 **MS. HUDSON:** Good afternoon, Mr. Chairman. I
17 hope it was okay; we went ahead and called our two
18 witnesses to take their seats at the panel. The
19 Office of Regulatory Staff witnesses are Gary Jones
20 and Ms. Allyn Powell. As they're getting situated,
21 I want to tell you and the Commissioners thank you,
22 for allowing us to utilize a panel. The same goes
23 to the parties, as well. Thank you.

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[Witnesses affirmed]

THEREUPON came,

G A R Y C . J O N E S ,

A L L Y N H . P O W E L L ,

called as witnesses on behalf of the South Carolina Office of
Regulatory Staff, who, having been first duly affirmed, were
examined and testified as follows:

DIRECT EXAMINATION

BY MS. HUDSON:

Q Mr. Jones, would you please state your name, occupation,
and business address?

A [JONES] my name is Gary C. Jones. I'm an engineering
consultant for Jones Partners, Limited, a private
consulting engineering firm in the electrical power
generation field. My address is 1222 West George
Street, Chicago, Illinois 60657-4220.

Q Have you ever testified before this Commission?

A [JONES] I have not.

Q Would you tell the Commission a little bit about your
background and nuclear experience?

A [JONES] Yes, I will. I'm going to go for good evening,
Mr. Chairman, and members of the Commission. I'll start
by saying that I have over 40 years' experience in the
international and domestic US nuclear power plants --
with US and international power plants. After

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1 graduating from the Tennessee Technological University
2 in Cookeville, Tennessee, with a Bachelor of Science
3 degree in Engineering Science, I began my career at
4 Sargent & Lundy, an internationally known consulting
5 engineering firm whose main offices are in Chicago,
6 Illinois. During my 32 years at Sargent & Lundy, I
7 worked with increasing levels of responsibility in the
8 design, engineering, and construction support of six new
9 US nuclear power plants. In addition, I led the S&L
10 engineering teams that reviewed the design of the first
11 indigenously designed Chinese nuclear power plant: Qin
12 Shan Unit 1. I also led teams providing engineering and
13 consulting services to operating nuclear power plants in
14 the US and internationally. I was a senior vice
15 president and owner at Sargent & Lundy, and retired at
16 the end of 2003.

17 After retiring from S&L, I worked for two and a
18 half years as a senior engineering safety officer at the
19 International Atomic Energy Agency, in Vienna, Austria.
20 I was team leader in the development, review, and
21 revision of International Nuclear Safety Standards and
22 assisting the member states of IAEA in the
23 implementation of those standards. One of my major
24 assignments is I led an IAEA team that assessed the 15
25 Ukrainian nuclear power plants for compliance with IAEA

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1 safety standards.

2 After leaving IAEA, I subsequently formed a private
3 consulting firm, which is Jones Partners, Limited, to
4 provide consulting services to electric power related
5 companies and organizations.

6 I am a professional engineer in the State of
7 Missouri and South Carolina. Thank you.

8 Q Thank you. Did you prepare or cause to be prepared 28
9 pages in answer-and-question format?

10 A [JONES] I did.

11 Q Do you have any changes, additions, or deletions to that
12 testimony?

13 A [JONES] I do not.

14 Q If you were asked those questions again, would your
15 answers remain the same?

16 A [JONES] They would.

17 Q Do you have any confidential information in your
18 testimony?

19 A [JONES] Yes, I do.

20 Q Would you please state the pages and line numbers that
21 confidential information is located on?

22 A [JONES] The confidential information is located on page
23 11, line 11; also on page 11, line 14; page 12, line
24 one; page 12, line 20; page 15, lines 17 and 18; page
25 17, line ten; page 24, lines four and eight.

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1 MS. HUDSON: Mr. Chairman, I would like to
2 call your and the Commissioners' attention to the
3 confidentially marked information on page 24, on
4 lines four and eight.

5 SCE&G provided testimony earlier today which
6 waived that confidential information. In essence,
7 they testified as to what that information is. I
8 notified SCE&G earlier, and I understand that they
9 agree that they waived that confidential
10 information. If I may, I would like confirmation
11 from SCE&G as to that.

12 MR. BURGESS: Mr. Chairman, that is correct.
13 That information on lines four and eight has been
14 disclosed, and we have no objections to Mr. Jones
15 removing the redaction on his testimony.

16 MS. HUDSON: Thank you. Once that redaction
17 is removed, it states the word "CHAMPS.net."

18 MS. GREENLAW: I'm sorry, what page are we on?

19 MS. HUDSON: Again, that is page 24, lines
20 four and eight.

21 Mr. Chairman, with that noted, the remaining
22 portions of the confidential are deemed
23 confidential by Commission Order 2012-623, and we'd
24 ask that Mr. Jones' public and redacted versions of
25 his testimony be treated as if they were read

1 orally from the stand, and be treated consistent
2 with that Commission Order.

3 CHAIRMAN WRIGHT: Mr. Jones's public and
4 confidential testimony will be entered into the
5 record of the case, and will be treated as
6 confidential, and the redacted version, the court
7 reporter will take that note into account.

8 [See pgs 1044-1072 ~ Public]

9 [See pgs 1074-1102 ~ Confidential]

10 MS. HUDSON: Thank you.

11 BY MS. HUDSON:

12 Q Mr. Jones, do you have two exhibits attached to your
13 testimony?

14 A [JONES] I do.

15 Q Do you have any changes, additions, or deletions to
16 those exhibits?

17 A [JONES] I do not.

18 Q Is there any confidential information in those exhibits?

19 A [JONES] No, there is not.

20 MR. GISSENDANNER: Mr. Chairman, we ask that
21 Mr. Jones' two exhibits be marked for
22 identification and entered into the record as the
23 next composite hearing exhibit.

24 CHAIRMAN WRIGHT: Mr. Jones's two exhibits
25 will be made a part of the record and evidence of

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1 the case, and it will be Exhibit No. 12.

2 [WHEREUPON, Hearing Exhibit No. 12 was
3 marked and received in evidence.]

4 BY MS. HUDSON:

5 Q Mr. Jones, do you have a summary of your testimony?

6 A [JONES] Yes, I do.

7 Q Would you please present that to the Commission?

8 A [JONES] Yes. Once again, good evening, Mr. Chairman and
9 members of the Commission. The purpose of my testimony
10 is to provide, on behalf of ORS, a technical review of
11 specific areas in SCE&G's request. The specific areas
12 which I will address are: The construction schedule,
13 including the Base Load Review Act milestones; the EPC
14 contract cost changes, excluding the wastewater
15 discharge piping and healthcare cost change orders; and
16 the owner's cost changes. Other areas of cost changes
17 included in this Petition will be addressed in the
18 testimony of ORS Witness Ms. Powell.

19 SCE&G has identified three major causes of the
20 11-1/2 month delay in the substantial completion date of
21 Unit 2, from April 1, 2016, until March 15, 2017. These
22 were: First, the nine-month delay in receiving the COL
23 from the NRC, which issued the COL on March 30, 2012,
24 instead of the originally anticipated date of July 1,
25 2011. Second, a delay of one additional month, due to

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1 excavated rock conditions for the nuclear island basemat
2 for Unit 2, requiring additional fill concrete beyond
3 that originally anticipated. And lastly, a delay of an
4 additional one and a half months, due to the increased
5 construction time associated with the complexity of the
6 shield building field assembly attributable to design
7 changes.

8 These construction changes also result in changes
9 to some of the BLRA milestone completion dates. ORS's
10 review of these changes to the schedule, and the basis
11 for each, indicated they appeared to be reasonable.
12 However, it must be noted the revised construction
13 schedule represents an aggressive and ambitious
14 construction approach that presents a risk to the on-
15 time completion of the project. While similar projects
16 are meeting and have met similarly aggressive
17 construction schedules in Asia, there is no precedent
18 for obtaining similar results on any modern nuclear
19 plant in the United States. This represents a challenge
20 to the project that will require rigorous diligence and
21 sustained commitment.

22 SCE&G is also requesting that the substantial
23 completion date for Unit 3 be accelerated to May 15,
24 2018, as compared to the currently approved date of
25 January 1, 2019. This reduces the interval between Unit

1 2 and Unit 3 to 14 months. The basis of this change was
2 reviewed and appeared to be reasonable, and represents a
3 cost-effective acceleration of the Unit 3 substantial
4 completion date.

5 SCE&G addressed four major reasons for the changes
6 to the EPC contract, as follows: First, the additional
7 costs incurred as a result of the delay in receiving the
8 COL from the NRC. Second, the additional costs
9 associated with the redesign and increased construction
10 cost of the shield building. Third, the additional
11 costs incurred as a result of the redesign of the
12 structural modules. And, fourth, the additional costs
13 incurred as a result of the bedrock under the Unit 2
14 nuclear island being deeper than the test borings
15 indicated.

16 In addition, there were three other change orders
17 that impacted the EPC contract costs, and were included
18 in this filing and identified as follows:

19 Cybersecurity, wastewater discharge piping, and
20 healthcare costs.

21 As previously stated, my testimony addresses the
22 four major reasons for the EPC cost changes and the
23 cybersecurity change order. ORS Witness Ms. Powell will
24 address the EPC cost change orders on wastewater
25 discharge piping and healthcare costs.

1 It should be noted that the four major reasons for
2 the EPC contract cost changes were bundled together and
3 negotiated with the consortium as a package. As stated
4 by the company in their filing and here, these changes
5 were subject to extensive negotiations extending over
6 several months before a compromise was reached and an
7 agreement was made to settle these claims for \$137.5
8 million, the amount requested in the filing. This
9 compromise represented a significant reduction from the
10 originally proposed amount of \$214 million. This final
11 negotiated value also included a credit from Shaw,
12 reflecting an acceleration of potential rebates.

13 Of the items I reviewed, I determined that all
14 costs, except for the \$4.95 million allocated to the
15 Phase 2 portion of the cybersecurity change order, were
16 reasonable. Therefore, I recommend that the \$137.5
17 million adjustment to the EPC contract and the \$914,422
18 change order representing Phase 1 of the cybersecurity
19 change order be approved.

20 Lastly, I reviewed the owner's costs where an
21 increase of approximately \$131.6 million was requested.
22 My review included the principal cost components of the
23 increase, which included a staffing analysis, a software
24 roadmap, and the multiunit facilities study. I also
25 reviewed the owners' cost categories that can be

1 identified as nonlabor-related changes to the operation
2 and maintenance, and construction of the units, and
3 miscellaneous cost increases associated with the paying
4 of various site licenses and permits, NRC fees,
5 insurance premiums, recruitment fees, and hiring and
6 other costs.

7 Based on my review, I determined the \$131.6 million
8 of increased owner's costs represents a reasonable cost
9 increase for the project. This concludes my summary.

10 MS. HUDSON: Thank you, Mr. Jones.

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23 [PURSUANT TO PREVIOUS INSTRUCTION, THE PREFILED
24 DIRECT TESTIMONY {PUBLIC VERSION} OF GARY C.
25 JONES FOLLOWS AT PGS 1044-1072]

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PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

**THE OFFICE OF REGULATORY STAFF
DIRECT TESTIMONY & EXHIBITS
OF**

GARY C. JONES, P.E.

AUGUST 9, 2012



DOCKET NO: 2012-203-E

**Petition of South Carolina Electric & Gas Company
for Updates and Revisions to Schedules Related to
the Construction of a Nuclear Base Load
Generation Facility at Jenkinsville, South Carolina**

(Redacted)

1

DIRECT TESTIMONY & EXHIBITS OF

2

GARY C. JONES, P.E.

3

ON BEHALF OF

4

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

5

DOCKET NO: 2012-203-E

6

IN RE: PETITION OF SOUTH CAROLINA ELECTRIC & GAS COMPANY FOR

7

UPDATES AND REVISIONS TO SCHEDULES RELATED TO THE CONSTRUCTION

8

OF A NUCLEAR BASE LOAD GENERATION FACILITY AT

9

JENKINSVILLE, SOUTH CAROLINA

10

11 **Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.**12 **A.**

My name is Gary C. Jones, P.E. I am President of Jones Partners, Ltd., a private

13

consulting engineering firm in the electrical power generation field. My business address is

14

1222 West George Street, Chicago, Illinois, 60657-4220.

15 **Q.****WHAT IS THE NATURE OF YOUR BUSINESS?**16 **A.**

As a private consultant, I provide professional engineering and consulting services

17

to clients in the electric power industry.

18 **Q.****PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**19 **A.**

I received a Bachelor of Science degree in Engineering Science from Tennessee

20

Technological University in Cookeville, Tennessee, where I also participated in the Co-

21

Operative Education Program with two one-year assignments at the Oak Ridge National

22

Laboratory in Oak Ridge, Tennessee. I worked for thirty-two years at Sargent & Lundy,

23

LLC, ("S&L") an international architect-engineering and consulting engineering firm in the

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1 electric power industry based in Chicago, Illinois. I held engineering positions of
2 increasing levels of responsibility working on the design, procurement, licensing,
3 construction support and start-up of nuclear power plant projects, culminating in the
4 position as Senior Vice President and one of the owners of the firm for the last sixteen
5 years of my tenure. I led the engineering activities associated with the design of six nuclear
6 power plants at three nuclear power plant stations, including the LaSalle County and
7 Braidwood plants for Commonwealth Edison (now Exelon) and the Marble Hill station for
8 Public Service Indiana. I also led the engineering activities associated with the restarts of
9 the LaSalle County Station Units 1 and 2 and the D.C. Cook Plant after these plants were
10 shut down due to operation concerns. I served for two years as head of the Mechanical
11 Department at S&L. I also led the engineering activities associated with services to
12 numerous operating nuclear power plants, including modifications, technical and economic
13 studies, licensing support, procedure and process development and other consulting
14 services.

15 Among the most significant assignments on international projects were leading the
16 design review of the first indigenous Chinese nuclear power plant, Qin Shan Unit 1, and
17 participating as a senior member in the design review of the Korean nuclear power plants
18 Yonggwang Units 3 and 4.

19 Upon my retirement from S&L, I established a private consulting practice, Jones
20 Partners, Ltd., where I continued working in the nuclear power industry for two and a half
21 years until I accepted a position at the International Atomic Energy Agency ("IAEA") in
22 Vienna, Austria. There I was a Senior Engineering Safety Officer in the Engineering Safety
23 Section of the Department of Nuclear Safety and Security. My assignments included

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1 developing international safety standards and performing safety reviews of nuclear power
2 plants. My most significant assignment was leading the safety review of the fifteen
3 operating nuclear power plants in the Ukraine.

4 Following the completion of my assignment at the IAEA, I returned to private
5 practice as a consultant to the power industry and continue that work today. I am a
6 licensed professional engineer in the States of Missouri and South Carolina. Additional
7 details of my work experience are provided in my resume which I have included as Exhibit
8 GCJ-1.

9 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE**
10 **COMMISSION OF SOUTH CAROLINA ("COMMISSION")?**

11 **A.** No. However, I have supplied testimony in various licensing, litigation and
12 arbitration proceedings in other venues.

13 **Q. WHAT IS YOUR ASSIGNMENT IN THIS PROCEEDING?**

14 **A.** My assignment is to assist the South Carolina Office of Regulatory Staff ("ORS")
15 in its monitoring and tracking of the construction schedule and budget related to South
16 Carolina Electric & Gas Company's ("SCE&G" or the "Company") V. C. Summer Units 2
17 & 3 (the "Units" or the "Project"). I began my assignment with ORS in August 2011.

18 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

19 **A.** The purpose of my testimony is to provide on behalf of ORS a technical review of
20 specific areas in SCE&G's request for updates and revisions to its capital cost schedule and
21 construction schedule for the Units as delineated in their petition under Docket No. 2012-
22 203-E ("Petition"). The specific areas which I will address are:

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- 1 • The construction schedule, including the Base Load Review Act ("BLRA")
2 milestones;
3 • The Engineering, Procurement and Construction Contract ("EPC Contract")
4 cost changes, excluding the Waste Water Discharge Piping and Health Care
5 Costs Change Orders; and,
6 • The Owners Cost changes.

7 Other areas of cost changes included in this Petition will be addressed in the
8 testimony of ORS witness Powell.

9 **Q. PLEASE DESCRIBE SCE&G'S REQUEST.**

10 **A.** SCE&G has filed this update to revise the construction schedules and capital cost
11 schedules approved through Commission Order No. 2011-345, and to supersede and
12 replace the petition filed on February 29, 2012 in Docket No. 2012-90-E. The primary
13 reasons for filing this Petition are:

- 14 • To change the construction schedule, including the Substantial Completion
15 Dates for the Units, which reflect the delay incurred due to the timing of
16 receiving the Combined Construction and Operating License ("COL") and other
17 delays associated with construction;
18 • To change the costs of the Units to reflect changes in the EPC Contract amount;
19 • To change the costs of the Units to reflect changes in the Owners Cost; and,
20 • To change costs of the Units to reflect changes to the transmission line costs.

21 The implications of these changes result in a delay of the Substantial Completion
22 Date of Unit 2 by 11½ months to March 15, 2017 and the acceleration of the Substantial

1 Completion Date of Unit 3 by 7½ months to May 15, 2018 from those dates previously
2 approved by the Commission of April 1, 2016 and January 1, 2019, respectively. This also
3 results in changes to many of the approved BLRA milestone dates. However, SCE&G
4 indicates that the delay of Unit 2 will not significantly affect the generating capacity during
5 the anticipated peak load in the summer of 2016 and the acceleration of Unit 3 results in
6 cost savings that partially offset the cost increases associated with the delay in the
7 completion date of Unit 2.

8 With regard to costs, the capital costs in 2007 dollars will increase by \$283.0
9 million, increasing the overall capital cost in 2007 dollars specified in Commission Order
10 No. 2011-345 from \$4.270 to \$4.553 billion. However, the updated cost schedule in future
11 dollars, including Allowance for Funds Used During Construction, is forecasted to be
12 approximately \$5.8 billion, which is \$25 million less than the forecast reflected in the most
13 recent Commission Order No. 2011-345. This is due primarily to actual escalation and
14 revised future escalation forecasts being lower than that reflected in the Order.

15 **Q. COULD YOU PLEASE ADDRESS THE CONSTRUCTION SCHEDULE**
16 **CHANGES AND YOUR REVIEW OF THE CHANGES IN MORE DETAIL?**

17 **A.** SCE&G has identified three major causes of the 11½ month delay in the Substantial
18 Completion Date of Unit 2. These were:

- 19 • The 9 month delay in receiving the COL from the Nuclear Regulatory
20 Commission ("NRC") which issued the COL on March 30, 2012 instead of
21 the originally anticipated July 1, 2011 date;